LODI CITY COUNCIL

Carnegie Forum

305 West Pine Street, Lodi

"SHIRTSLEEVE" SESSION

Date: November 22, 2005

Time: 7:00 a.m.

For information regarding this Agenda please contact:
Susan J. Blackston
City Clerk
Telephone: (209) 333-6702

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Informal Informational Meeting

A. Roll call by City Clerk

B. Topic(s)

B-1 Utilities Quarterly Report (EUD / PW)

C. Comments by public on non-agenda items

D. Adjournment

Pursuant to Section 54954.2(a) of the Government Code of the State of California, this agenda was posted at least 72 hours in advance of the scheduled meeting at a public place freely accessible to the public 24 hours a day.

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Susan J. Blackston
City Clerk

City of Lodi – City Hall
221 W. Pine Street
Lodi, CA 95240
Phone: (209) 333-6700
Fax: (209) 333-6807

TO: Honorable Members of the City Council

THROUGH: Blair King, City Manager

FROM: Jim Krueger, Finance Director

DATE: November 15, 2005

SUBJECT: Financial Ratios for Utility Funds

Attached is a brief financial analysis of the City's three Utility Funds. This same type of analysis will be included in the future Quarterly reviews of these funds. These ratios are not exhaustive and there will be other analyses included in the future evaluations you will receive.

The most recent three fiscal years ending June 30, 2003, 2004 and 2005 are included for your review. The analysis relates to only Balance Sheet accounts only and includes Asset , Liability and Equity ratios. Other relevant ratios including income related information will be included in future Quarterly reviews.

City of Lodi
Utility Funds Financial Ratios
For Fiscal Years 2003-2005

	2003			2004			Unaudited 2005		
	Electric	Water	Wastewater	Electric	Water	Wastewater	Electric	Water	Wastewater
Cash	771,588	292,301	769,770	6,347,087	1,442,231	4,568,925	4,896,603	4,300,091	584,922
Current Assets	33,516,295	5,846,176	3,258,822	34,030,202	2,470,279	32,383,623	24,988,681	5,312,046	19,635,948
Current Liablitities	6,347,522	3,003,547	923,228	11,656,259	2,268,525	4,568,869	3,707,651	2,799,048	2,787,966
Net Current Assets	27,168,773	2,842,629	2,335,594	22,373,943	201,754	27,814,754	21,281,030	2,512,998	16,847,982
Current Ratio	5.28	1.95	3.53	2.92	1.09	7.09	6.74	1.90	7.04
Total Assets	106,569,576	24,102,825	39,111,371	106,864,572	24,664,084	79,549,872	94,560,612	25,530,897	75,463,733
Total Liabilities	88,786,669	27,529,144	10,503,566	91,170,428	25,817,806	46,433,364	81,286,022	4,912,327	43,571,502
Net Assets	17,782,907	-3,426,319	28,607,805	15,694,144	-1,153,722	33,116,508	13,274,590	20,618,570	31,892,231
Net Assets /Assets	0.17	-0.14	0.73	0.15	-0.05	0.42	0.14	0.81	0.42
Debt/Equity	4.99	-8.03	0.37	5.81	-22.38	1.40	6.12	0.24	1.37

Source: City of Lodi Comprehensive Annual Financial Reports

AGENDA ITEM B-01

CITY OF LODI
COUNCIL COMMUNICATION

AGENDA TITLE: **Receive financial data on Electric Utility operations (EUD)**

MEETING DATE: **November 22, 2005**

PREPARED BY: **Interim Electric Utility**

RECOMMENDED ACTION: No Council action is required. Data is being provided for informational purposes only.

BACKGROUND INFORMATION: On October 18, 2005 a presentation was made to the city council entitled "Update on Electric Utilities Financial position, Market Cost Adjustment and Recent Power Purchases". A copy of that presentation is attached. The purpose of that presentation was to bring the Council up to date on the financial results leading up to fiscal year 2006 and to provide a brief snapshot of finances post 2006. As part of that presentation, staff explained that the Electric Department had established a plan to address the immediate financial problems affecting the utility which consisted of 1) stabilizing purchased power costs, 2) correcting revenue/expense imbalances through the application of a Market Cost Adjustment and 3) Implementing a long term rate structure and financial plan.

Issue: The long term financial plan includes a risk management program. Key elements of that plan include:

- Identification of standardized reports that will be provided to the city council that are necessary to ensure oversight of the electric utility;
- Identification of the frequency, method and individual responsible for preparation and transmission of the standardized reports;
- Establishment of procurement policies:
    - Recommended amounts of energy to procure on an advance basis versus the spot market
    - Recommended amounts of energy to procure through contract versus ownership
    - Recommended term lengths for procurement contracts, and
    - Authorization limits, checks and balances associated with procurement authorizations
- Recommendations for implementing the risk management program.

Until the long-term financial plan can be completed, and the specific reporting elements identified, staff is presenting the following reports for council review:

- Electric Utility Proforma for fiscal years 2003 through 2011;
- A summary of the net open position for the electric utility through the balance of fiscal year 2006; (this report will be provided at the Tuesday morning Shirtsleeve Session)
- A summary of the net open position for the electric utility for fiscal year 2007; and
- A summary of revenues collected from the base rates and market cost adjustment by month, as required pursuant to the Market Cost Adjustment Ordinance reporting requirements (this report will be provided at the Tuesday morning Shirtsleeve Session)

APPROVED: _____
Blair King, City Manager

These reports are being provided in order to establish a culture of providing quarterly oversight reports to the City Council and to conform to the spirit of a risk management program, which includes regular reporting of results.

FISCAL IMPACT: There is no fiscal impact associated with this quarterly reporting.

FUNDING: Not Applicable

_____
David Dockham
Interim Electric Utility Director

DD/lst

Attachments

cc: City Attorney
Finance Director

Update on Electric Utility's financial position, Market Cost Adjustment and recent power purchases

City Council Shirtsleeve Session

October 18, 2005

Overview

- Financial focus will be on FY06
  - Financial results leading up to FY06
  - Brief treatment of finances post 2006
- Second step of three step process
  1. Stabilize purchase power costs
  2. Correct the Revenue/Expense Imbalance (MCA)
  3. Implement long term rate structure and financial plan

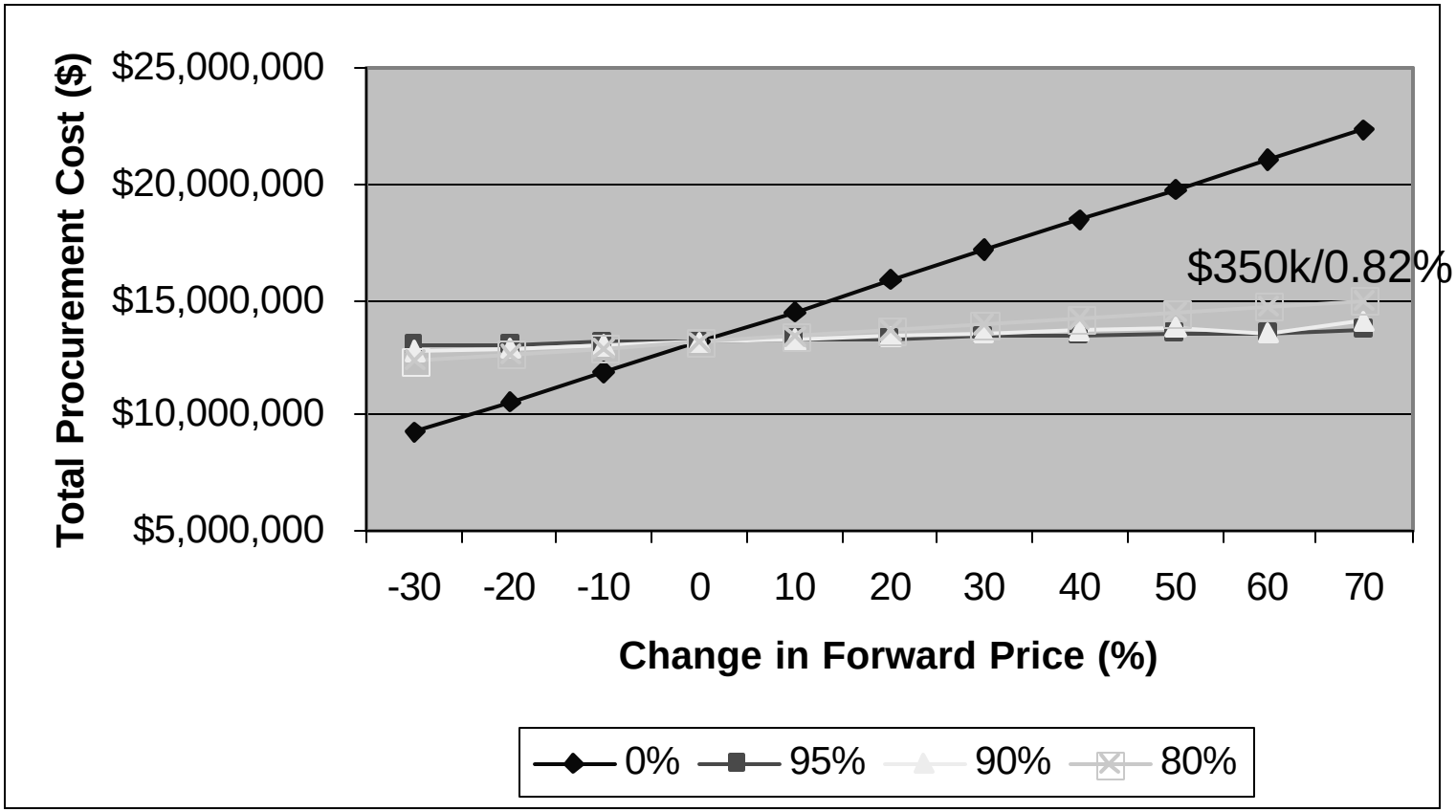
Stabilize Purchase Power Costs

November – June	$11.6 million
October balance of month	$ .6 million
Total	$12.2 million
September open position	$ .1 million
Total	$12.3 million
Estimate for purchase	$13.1 million
Reduction from estimate	$ .8 million

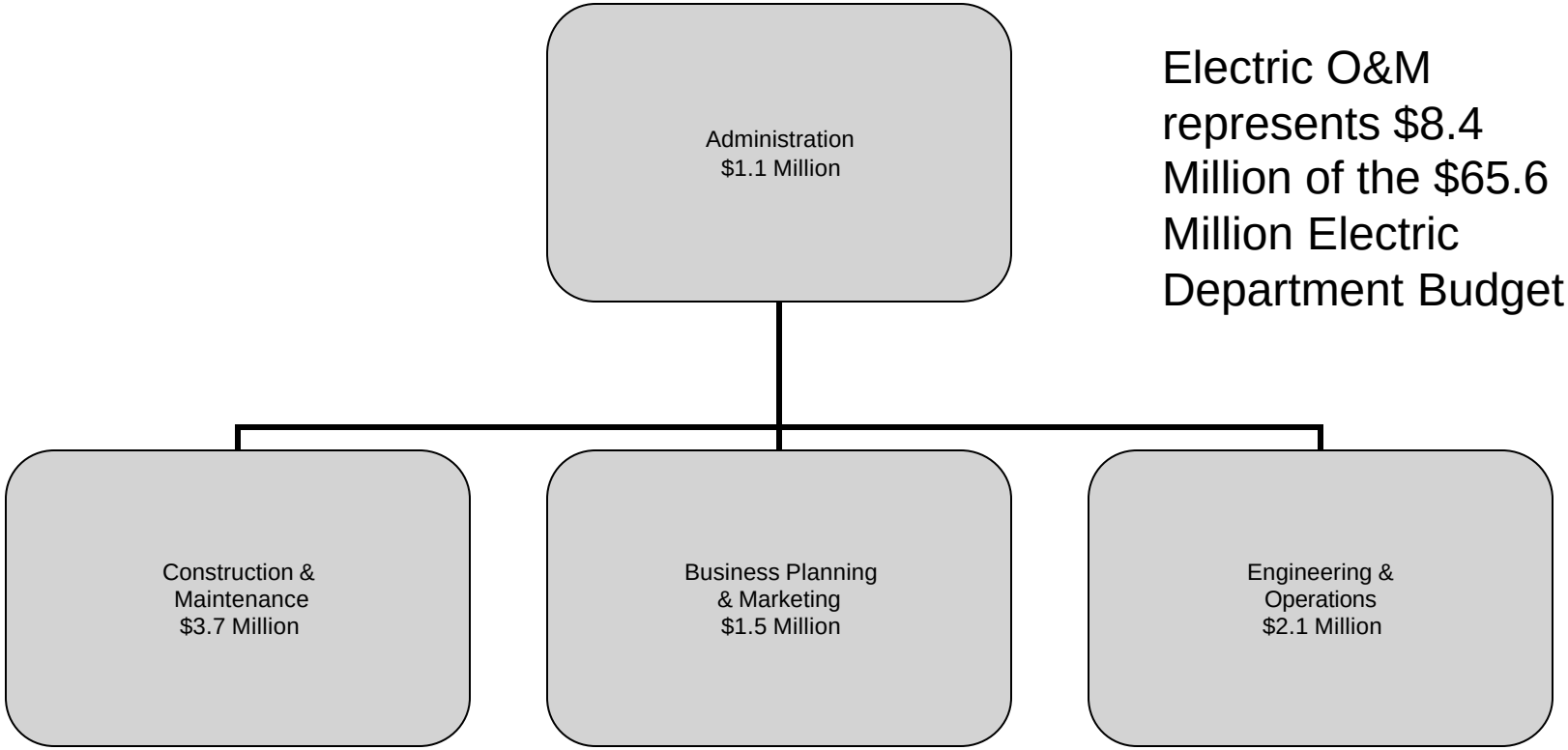
Ongoing results

- October prices have been choppy
- Future prices have stabilized or flattened
- Price volatility still a significant risk
- A turbine failure at NCPA's Geo 4 plant has resulted in reduced output from plant to participants
  - Additional purchase needed to get to 95%
  - Represents approximately 6% of requirement in November and December
  - Estimated cost of $250k per month

Open Position Sensitivity to Price Changes (9/27/2005)

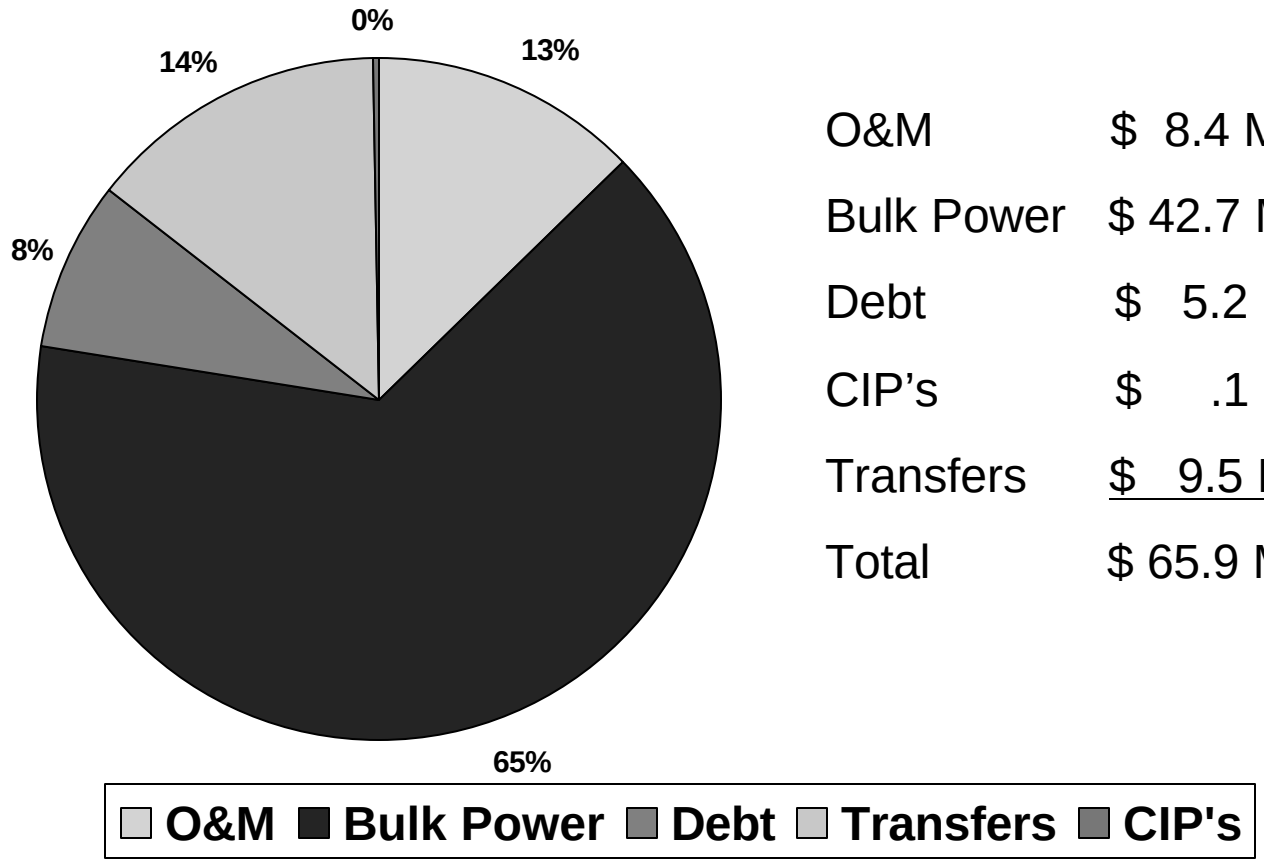


Organizational Background



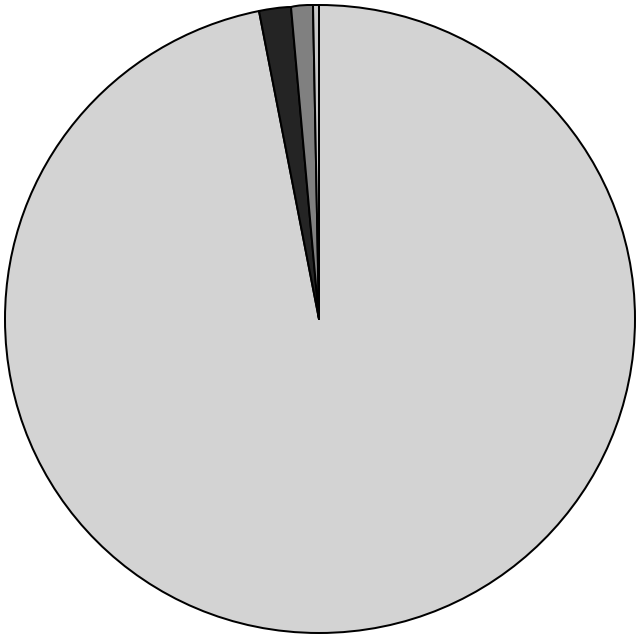
Electric O&M represents $8.4 Million of the $65.6 Million Electric Department Budget

Financial Structure - Expenses



O&M	$ 8.4 Million
Bulk Power	$ 42.7 Million
Debt	$ 5.2 Million
CIP's	$ .1 Million
Transfers	$ 9.5 Million
Total	$ 65.9 Million

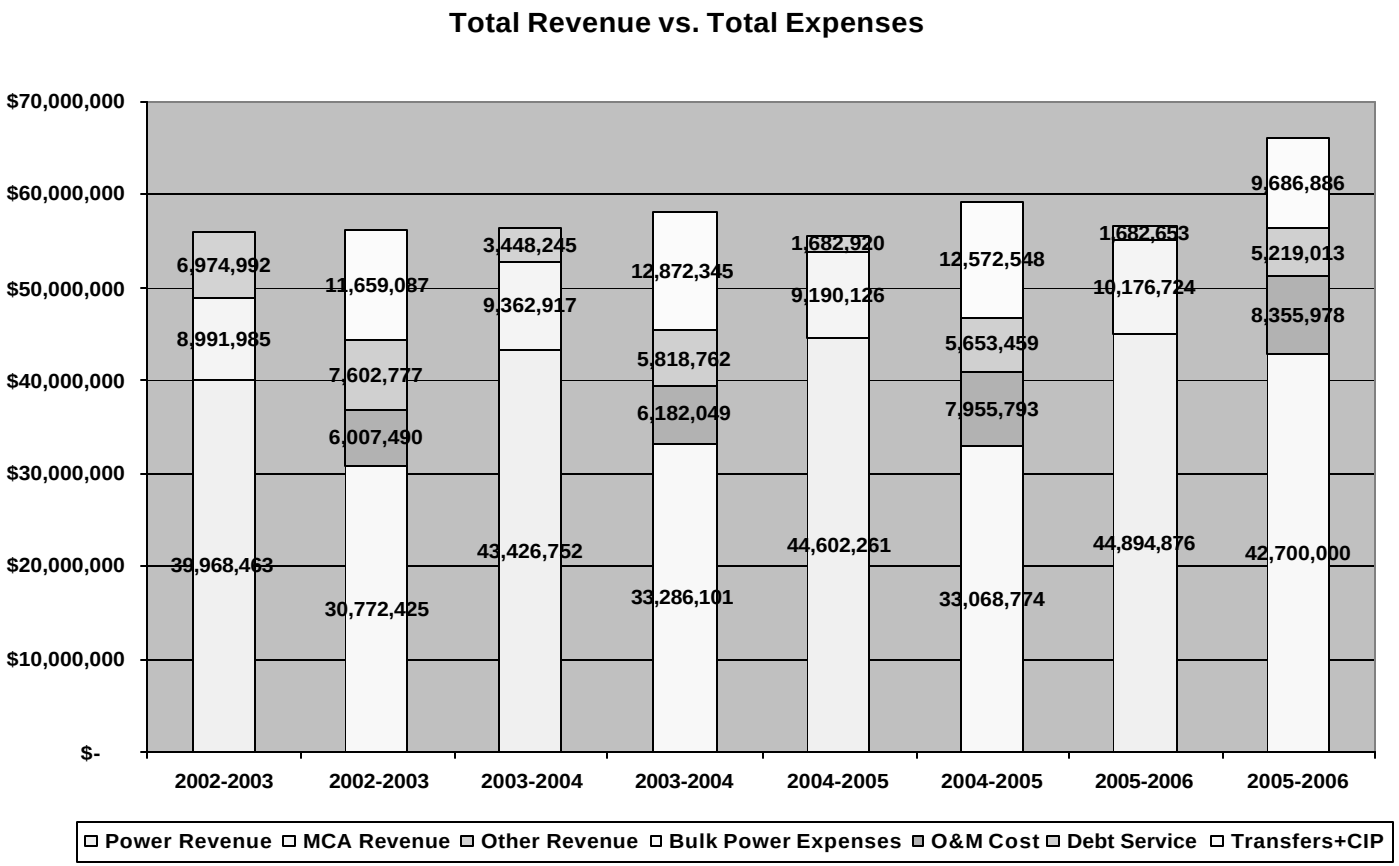
Financial Structure – Revenues



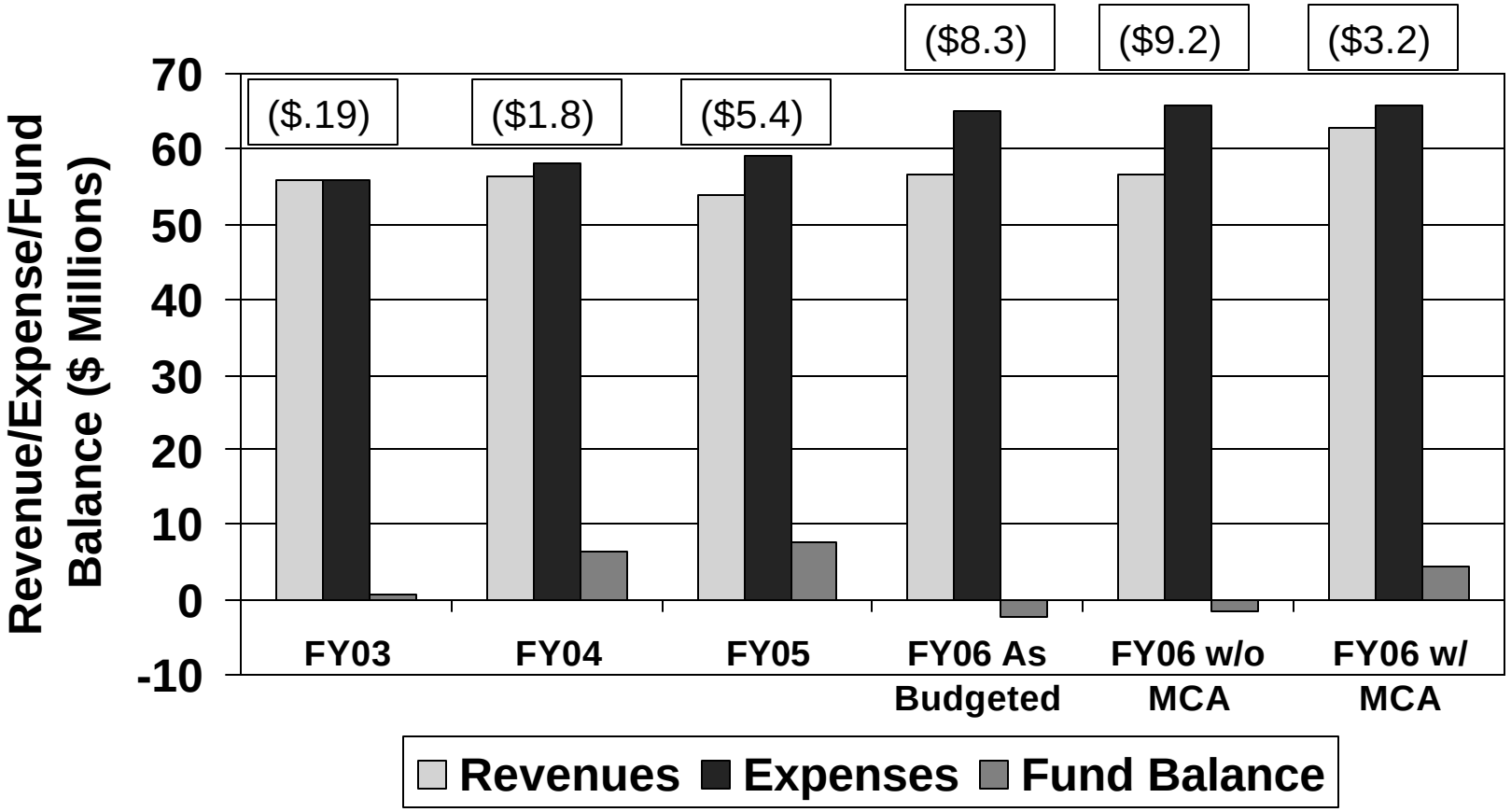
Power Sales	$ 55.1 Million
Investments	$ .95 Million
Services	$ .59 Million
Other	$ .14 Million
Total	$ 56.7 Million

Power Sales **Investments** **Services** **Other**

Financial Structure – Revenues and Expenses



Cash Flow Analysis of Financial Structure



Causes of Revenue Imbalances

- Rapidly increasing costs of power supply in FY06
- No rate adjustments since 2002 to address generally increasing revenue and expense imbalances
- Discounted rates for largest users

Change in Power Supply Costs Over Time

	FY03	FY04	FY05	FY06 As Budgeted	FY06 As Forecast
Power Supply Cost ($M)	$30.8	$32.3	$33.1	$39.8	$42.7
% Change from prior year	n/a	4.9%	2.5%	20.2%	29.0%
% change from last MCA	n/a	4.9%	7.5%	29.2%	38.6%

Attachment 1 - Electric Department Proforma Fiscal Years 2003 to 2011

	FY03 Actual	FY04 Actual	FY05 Actual	FY06 Budget	FY06 Forecast w/o MCA	FY06 Forecast w/ MCA	FY07 Forecast	FY08 Forecast	FY09 Forecast	FY10 Forecast	FY11 Forecast
Total Revenue											
Power Sales	$48,872,490	$52,898,903	$53,792,387	$55,071,600	$55,071,600	$61,071,600	$65,000,000	$66,950,000	$68,958,500	$71,027,255	$73,158,073
Rate Stabilization Fund Withdrawal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Revenue	$6,974,992	$3,448,245	$1,682,920	$1,682,653	$1,682,653	$1,682,653	$590,000	$607,700	$625,931	$644,709	$664,050
Total Revenues	$55,847,482	$56,347,148	$55,475,307	$56,754,253	$56,754,253	$62,754,253	$65,590,000	$67,557,700	$69,584,431	$71,671,964	$73,822,123
Total Expenses											
Purchased Power	$30,772,425	$33,286,101	$33,068,774	$39,833,099	$42,700,000	$42,700,000	$43,200,000	$39,190,000	$41,200,000	$45,979,000	$44,169,000
Non-Power Costs	$6,007,490	$6,182,049	$7,955,793	$10,401,497	$8,355,978	$8,355,978	$8,658,041	$8,961,072	$9,274,710	$9,599,325	$9,935,301
Total Expenses	$36,779,915	$39,468,150	$41,024,567	$50,234,596	$51,055,978	$51,055,978	$51,858,041	$48,151,072	$50,474,710	$55,578,325	$54,104,301
Net Revenue	$19,067,567	$16,878,998	$14,450,740	$6,519,657	$5,698,275	$11,698,275	$13,731,959	$19,406,628	$19,109,721	$16,093,639	$19,717,822
Less: Net Debt Service	$7,602,777	$5,818,762	$5,653,459	$5,219,013	$5,219,013	$5,219,013	$5,685,954	$8,551,804	$6,048,532	$6,483,111	$6,483,111
Net Income -- Cash Basis	$11,464,790	$11,060,236	$8,797,281	$1,300,644	$479,262	$6,479,262	$8,046,005	$10,854,824	$13,061,189	$9,610,528	$13,234,711
Less: Transfers & CIP's	$11,659,087	$12,872,345	$12,572,548	$9,586,886	$9,686,886	$9,686,886	$9,653,185	$11,245,796	$11,599,229	$11,963,827	$12,339,944
Plus: Reimbursements from COP's	$0	$0	$0	$0	$0	$0					
Less: RSF Deposits	$0	$0	$0	$0	$0	$0					
Less: Working Capital Fund Deposits	$0	$0	$0	$0	$0	$0					
Operating Income - Accrual Basis	($194,297)	($1,812,109)	($3,775,267)	($8,286,242)	($9,207,624)	($3,207,624)	($1,607,180)	($390,973)	$1,461,960	($2,353,299)	$894,766
Working Capital Reserve (FYE)											
Rate Stabilization Fund (FYE)	$6,241,447	$6,260,483	$1,897,989	$0	$0	$0					
Electric Operating Fund FYE	($5,469,859)	$86,604	$5,615,938	($772,315)	($6,388,253)	($3,207,624)					
Working Capital FY End	$771,588	$6,347,087	$7,513,927	($772,315)	($1,693,697)	$4,306,303	$2,699,123	$2,308,151	$3,770,111	$1,416,812	$2,311,578
Coverage (including RSF draws)	2.51	2.90	2.56	1.25	1.09	2.24	2.42	2.27	3.16	2.48	3.04

Attachment 3

Nov. 8, 2005

		Lodi Total Surplus/(Deficit)	Load	% of Load	Lodi HLH Surplus/(Deficit)	Load	% of Load	Lodi LLH Surplus/(Deficit)	Load	% of Load	HLH $/MWH	LLH $/MWH
2006	**July**	(23,022)	50,000	-46.0%	(11,075)	31,145	-35.6%	(11,947)	18,855	-63.4%	$ 97.00	$ 67.90
	August	(28,019)	51,590	-54.3%	(17,244)	34,620	-49.8%	(10,774)	16,969	-63.5%	$ 102.00	$ 71.40
	September	(18,857)	44,534	-42.3%	(9,420)	28,359	-33.2%	(9,437)	16,175	-58.3%	$ 98.00	$ 71.05
	October	(21,547)	38,724	-55.6%	(13,083)	24,852	-52.6%	(8,464)	13,872	-61.0%	$ 90.00	$ 72.00
	November	(33,293)	37,593	-88.6%	(22,643)	23,833	-95.0%	(10,650)	13,759	-77.4%	$ 86.00	$ 68.80
	December	(36,412)	38,673	-94.2%	(24,662)	23,641	-104.3%	(11,750)	15,032	-78.2%	$ 88.00	$ 70.40
2007	**January**	(33,164)	38,621	-85.9%	(20,099)	24,749	-81.2%	(13,064)	13,873	-94.2%	$ 90.00	$ 67.50
	February	(29,008)	34,883	-83.2%	(17,334)	22,636	-76.6%	(11,674)	12,247	-95.3%	$ 88.00	$ 66.00
	March	(31,061)	37,664	-82.5%	(21,350)	24,603	-86.8%	(9,711)	13,060	-74.4%	$ 82.00	$ 61.50
	April	(21,249)	38,029	-55.9%	(11,925)	24,099	-49.5%	(9,324)	13,930	-66.9%	$ 80.00	$ 60.00
	May	(18,024)	40,735	-44.2%	(11,612)	26,442	-43.9%	(6,411)	14,293	-44.9%	$ 76.00	$ 57.00
	June	(18,910)	44,888	-42.1%	(11,521)	29,705	-38.8%	(7,389)	15,183	-48.7%	$ 82.00	$ 61.50
	FY Total	(312,564)	495,933	-63.0%	(191,969)	318,683	-60.2%	(120,595)	177,249	-68.0%		

Assumptions:

Zero STIG and CT1 generation.
Average hydro conditions for Calaveras Project, Western Base Resource, and market prices.
Forward electricity prices based on Nov. 8, 2005 TFS Energy indications.
There are no forward energy transactions for Lodi during this period.

INDICATED COST OF DEFICIT ENERGY BALANCES

	Total Cost	HLH Cost	LLH Cost
2006 July	$ (1,885,436)	$ (1,074,227)	$ (811,209)
August	$ (2,528,189)	$ (1,758,895)	$ (769,295)
September	$ (1,593,628)	$ (923,162)	$ (670,467)
October	$ (1,786,914)	$ (1,177,504)	$ (609,411)
November	$ (2,680,000)	$ (1,947,285)	$ (732,714)
December	$ (2,997,456)	$ (2,170,256)	$ (827,200)

2007	**January**	$ (2,690,777)	$ (1,808,948)	$ (881,829)
	February	$ (2,295,904)	$ (1,525,423)	$ (770,481)
	March	$ (2,347,932)	$ (1,750,706)	$ (597,226)
	April	$ (1,513,411)	$ (953,978)	$ (559,434)
	May	$ (1,247,976)	$ (882,537)	$ (365,439)
	June	$ (1,399,159)	$ (944,737)	$ (454,422)
	Total July-June	$ (24,966,783)	$ (16,917,656)	$ (8,049,127)

Handouts For November 22, 2005 Shirtsleeve Session

- **Summary of Market Transactions by Month**
- **Summary of Net Open Position for Balance of Fiscal Year 2006**
- **Summary of Revenues Collected from Base Rates and Market Cost Adjustments**
- **Example Risk Management Report from Palo Alto**

DECEMBER HLH TRANSACTIONS:			$/mwh	$
DEAL ID	416 hrs/MWH			
1009624	5	2080	$ 68.90	$ 143,312
1011692	25	10400	$ 112.75	$ 1,172,600
1009776	10	4160	$ 74.40	$ 309,504
1009873	10	4160	$ 72.25	$ 300,560
1011700	8	3328	$ 118.50	$ 394,368
HLH sum	58	24128	$ 446.80	$ 2,320,344
Average Price ($/mwh)	$ 96.17			

DECEMBER LLH TRANSACTIONS:			$/mwh	$
DEAL ID	328 hrs/MWH			
1011696	16	5248	$ 97.75	$ 512,992
1009624	5	1640	$ 68.90	$ 112,996
1009776	5	1640	$ 53.65	$ 87,986
HLH sum	26	8528	$ 220.30	$ 713,974
Average Price ($/mwh)	$ 83.72			

December Totals

32656 MWH
$ 3,034,318 Cost
$ 92.92 $/MWH avg.

JANUARY HLH TRANSACTIONS:				
DEAL ID	416 hrs/MWH			
1009624	5	2080	$ 68.90	$ 143,312
1009776	5	2080	$ 74.40	$ 154,752
1009873	10	4160	$ 72.25	$ 300,560
1011693	25	10400	$ 113.00	$ 1,175,200
1011700	12	4800	$ 123.00	$ 590,400
HLH sum	57	23520	$ 451.55	$ 2,364,224
Average Price ($/mwh)	$ 100.52			

JANUARY LLH TRANSACTIONS:				
DEAL ID	328 hrs/MWH			
1009624	5	1640	$ 68.90	$ 112,996
1009776	5	1640	$ 53.65	$ 87,986
1011696	14	4592	$ 98.00	$ 450,016
HLH sum	24	7872	$ 220.55	$ 650,998
Average Price ($/mwh)	$ 82.70			

Jan. 2006 Totals

31392 MWH
$ 3,015,222 Cost
$ 96.05 $/MWH avg.

FEBRUARY HLH TRANSACTIONS:				
DEAL ID	384 hrs/MWH			
1009624	5	1920	$ 68.90	$ 132,288
1009776	5	1920	$ 74.40	$ 142,848
1009873	10	3840	$ 72.25	$ 277,440
1011693	25	9600	$ 113.00	$ 1,084,800
1011700	5	1920	$ 118.50	$ 227,520
HLH sum	50	19200	$ 447.05	$ 1,864,896
Average Price ($/mwh)	$ 97.13			

FEBRUARY LLH TRANSACTIONS:				
DEAL ID	288 hrs/MWH			
1009624	5	1440	$ 68.90	$ 99,216
1009776	5	1440	$ 53.65	$ 77,256
1011696	12	3456	$ 98.00	$ 338,688
HLH sum	22	6336	$ 220.55	$ 515,160
Average Price ($/mwh)	$ 81.31			

Feb. 2006 Totals

25536 MWH
$ 2,380,056 Cost
$ 93.20 $/MWH avg.

MARCH HLH TRANSACTIONS:				
DEAL ID	432 hrs/MWH			
1009624	5	2160	$ 68.90	$ 148,824
1009776	5	2160	$ 74.40	$ 160,704
1009873	5	2160	$ 72.25	$ 156,060
1011693	25	10800	$ 113.00	$ 1,220,400
1011700	6	2592	$ 116.00	$ 300,672
HLH sum	46	19872	$ 444.55	$ 1,986,660
Average Price ($/mwh)	$ 99.97			

MARCH LLH TRANSACTIONS:				
DEAL ID	312 hrs/MWH			
1009624	5	1560	$ 68.90	$ 107,484
1009776	5	1560	$ 53.65	$ 83,694
1011696	10	3120	$ 98.00	$ 305,760
HLH sum	20	6240	$ 220.55	$ 496,938
Average Price ($/mwh)	$ 79.64			

March 2006 Totals

26112 MWH
$ 2,483,598 Cost
$ 95.11 $/MWH avg.

Month Totals

APRIL HLH TRANSACTIONS:

DEAL ID	400 hrs/MWH			
1009624	5	2000	$ 68.90	$ 137,800
1009873	5	2000	$ 72.25	$ 144,500
1011694	19	7600	$ 70.25	$ 533,900
HLH sum	29	11600	$ 211.40	$ 816,200
Average Price ($/mwh)	$ 70.36			

APRIL LLH TRANSACTIONS:

DEAL ID	319 hrs/MWH			
1009624	5	1595	$ 68.90	$ 109,896
1011698	10	3190	$ 70.00	$ 223,300
1009776	5	1595	$ 53.65	$ 85,572
HLH sum	20	6380	$ 192.55	$ 418,767
Average Price ($/mwh)	$ 65.64			

April 2006 Totals

17980 MWH
$ 1,234,967 Cost
$ 68.69 $/MWH avg.

MAY HLH TRANSACTIONS:

DEAL ID	416 hrs/MWH			
1009624	5	2080	$ 68.90	$ 143,312
1009776	5	2080	$ 74.40	$ 154,752
1009873	5	2080	$ 72.25	$ 150,280
1011695	11	4576	$ 70.25	$ 321,464
HLH sum	26	10816	$ 285.80	$ 769,808
Average Price ($/mwh)	$ 71.17			

MAY LLH TRANSACTIONS:

DEAL ID	328 hrs/MWH			
1009624	5	1640	$ 68.90	$ 112,996
1009776	5	1640	$ 53.65	$ 87,986
1011697	5	1640	$ 57.00	$ 93,480
HLH sum	15	4920	$ 179.55	$ 294,462
Average Price ($/mwh)	$ 59.85			

May 2006 Totals

15736 MWH
$ 1,064,270 Cost
$ 67.63 $/MWH avg.

JUNE HLH TRANSACTIONS:

DEAL ID	416 hrs/MWH			
1009624	5	2080	$ 68.90	$ 143,312
1009873	5	2080	$ 72.25	$ 150,280
1011701	12	4992	$ 92.00	$ 459,264
HLH sum	22	9152	$ 233.15	$ 752,856
Average Price ($/mwh)	$ 82.26			

JUNE LLH TRANSACTIONS:

DEAL ID	304 hrs/MWH			
1009624	5	1520	$ 68.90	$ 104,728
1009776	5	1520	$ 53.65	$ 81,548
1011699	8	2432	$ 61.75	$ 150,176
HLH sum	18	5472	$ 184.30	$ 336,452
Average Price ($/mwh)	$ 61.49			

June 2006 Totals

14624 MWH
$ 1,089,308 Cost
$ 74.49 $/MWH avg.

Attachment 2 - Summary of Net Open Position for Balance of Fiscal Year 2006

Nov. 8, 2005

	Lodi Total Surplus/(Deficit)	Load	% of Load	Lodi HLH Surplus/(Deficit)	Load	% of Load	Lodi LLH Surplus/(Deficit)	Load	% of Load	HLH $/MWH	LLH $/MWH
2005 December	(5,110)	37,646	-13.6%	(2,697)	24,564	-11.0%	(2,413)	13,083	-18.4%	$ 89.50	$ 70.50
2006 January	(157)	37,649	-0.4%	1,191	24,183	4.9%	(1,348)	13,466	-10.0%	$ 94.50	$ 80.50
February	(2,630)	33,913	-7.8%	(1,264)	22,005	-5.7%	(1,366)	11,907	-11.5%	$ 92.00	$ 69.00
March	(1,646)	36,701	-4.5%	(433)	24,022	-1.8%	(1,213)	12,678	-9.6%	$ 89.50	$ 65.34
April	(2,892)	37,076	-7.8%	(1,333)	23,423	-5.7%	(1,559)	13,653	-11.4%	$ 78.00	$ 55.38
May	(2,050)	39,812	-5.1%	(291)	25,842	-1.1%	(1,759)	13,970	-12.6%	$ 74.00	$ 53.28
June	(3,396)	43,980	-7.7%	(1,408)	29,135	-4.8%	(1,988)	14,845	-13.4%	$ 80.00	$ 60.00
Total	(17,881)	266,776	-6.7%	(6,235)	173,174	-3.6%	(11,646)	93,602	-12.4%		

Assumptions: Zero STIG and CT1 generation.
Average hydro conditions for Calaveras Project, Western Base Resource, and market prices.
Forward electricity prices based on Nov. 8, 2005 TFS Energy indications.
There are no forward energy transactions for Lodi during this period.

INDICATED COST OF DEFICIT ENERGY BALANCES

	Total Cost	HLH Cost	LLH Cost
2005 December	$ (411,516)	$ (241,404)	$ (170,112)
January	$ 4,045	$ 112,548	$ (108,504)
February	$ (210,517)	$ (116,259)	$ (94,258)
March	$ (118,033)	$ (38,770)	$ (79,263)
April	$ (190,292)	$ (103,957)	$ (86,335)
May	$ (115,243)	$ (21,541)	$ (93,701)
2006 June	$ (231,921)	$ (112,635)	$ (119,285)
Total Dec-June	$ (1,273,476)	$ (522,018)	$ (751,459)
SPOT net PURC. COST (est) $/MWH (avg.)	**$ 71.2 /mwh**	**$ 83.7 /mwh**	**$ 64.5 /mwh**

REVENUE - EXPENSE SUMMARY				
REVENUE	**Jul-05**	**Aug-05**	**Sep-05**	**YEAR TO DATE**
MCA	$ 1,029,698	$1,221,116	$ 930,006	$ 3,180,820
RATE BASE	$ 4,828,766	$5,417,882	$4,545,061	$ 14,791,709
OTHER REVENUE	$ 32,247	$ 6,665	$ 29,751	$ 68,663
SUB TOTAL	$ 5,890,712	$6,645,662	$5,504,818	$ 18,041,192
EXPENSE				
O & M	$ 3,726,026	$4,182,644	$3,140,987	$ 11,049,657
TRANS & PILOT	$ 787,354	$ 787,354	$ 787,354	$ 2,362,061
DS	$ 434,918	$ 434,918	$ 434,918	$ 1,304,753
CAPITAL	$ 134,609	$ 234,227	$ 123,269	$ 492,105
SUB TOTAL	$ 5,082,906	$5,639,142	$4,486,527	$ 15,208,576
TOTAL (Net):	$ 807,806	$1,006,520	$1,018,290	$ 2,832,616

REVENUE - EXPENSE SUMMARY				
REVENUE	**Jul-04**	**Aug-04**	**Sep-04**	**YEAR TO DATE**
MCA	$ 1,059,646	$1,041,220	$ 979,009	$ 3,079,875
RATE BASE	$ 4,762,069	$4,760,998	$4,550,363	$ 14,073,430
OTHER REVENUE	$ 137,626	$ 1,265	$ 5,580	$ 144,471
SUB TOTAL	$5,959,341	$5,803,483	$5,534,952	$ 17,297,776
EXPENSE				
O & M	$ 3,650,605	$2,633,740	$3,377,247	$ 9,661,592
TRANS & PILOT	$ 836,868	$ 857,491	$ 856,091	$ 2,550,450
DS	$ 450,890	$ 450,890	$ 450,890	$ 1,352,670
CAPITAL	$ -	$ -	$ -	$ -
SUB TOTAL	$ 4,938,363	$3,942,121	$4,684,228	$ 13,564,711
TOTAL (Net):	$ 1,020,978	$1,861,362	$ 850,725	$ 3,733,065

ITEM 5

TO: HONORABLE CITY COUNCIL

FROM: CITY MANAGER **DEPARTMENT:** ADMINISTRATIVE SERVICES

DATE: MAY 2, 2005 **CMR:** 226:05

SUBJECT: CITY OF PALO ALTO'S ENERGY RISK MANAGEMENT REPORT FOR THE THIRD QUARTER, FISCAL YEAR 2004-2005

This is an information report and no action is required.

BACKGROUND

The purpose of this report is to inform the City Council of the status of the City's energy portfolio and transactions executed with energy suppliers as of the end of the third quarter of Fiscal Year 2004-05. The City's Energy Risk Management Policy requires that staff report on a quarterly basis to Council on: 1) the City's energy portfolio, 2) the City's credit and market risk profile, 3) portfolio performance, and 4) other key market and risk information.

DISCUSSION

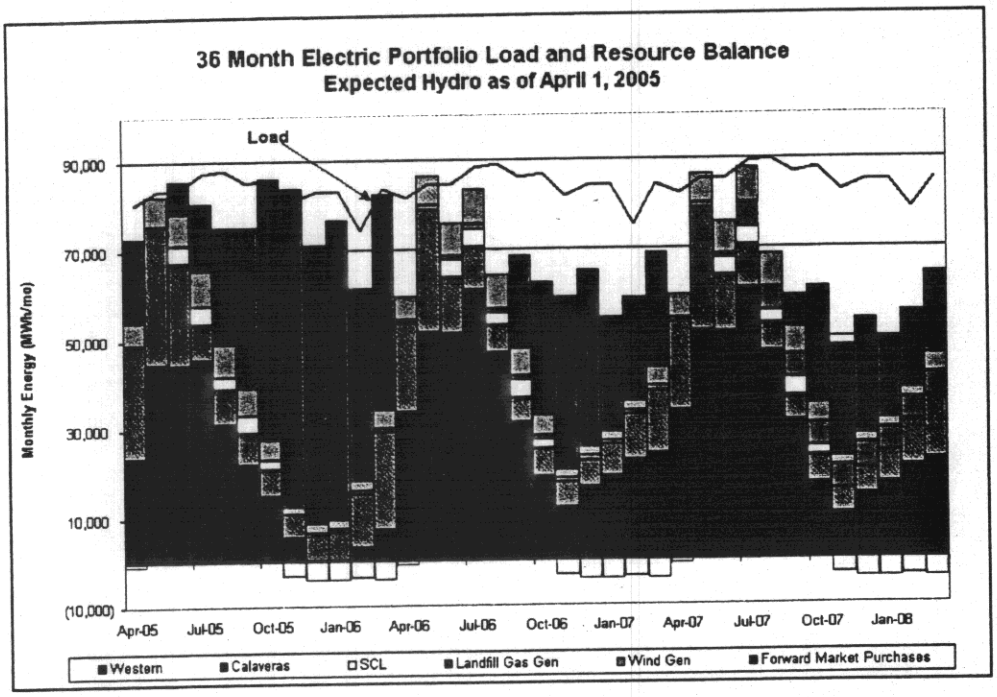
Open Transactions as of March 31, 2005

Open transactions are commitments that the City has made to purchase either electricity or gas, but for which supplies have not yet been delivered. The analysis presented here is restricted to forward fixed price purchases with corporate counterparties, and, except where specifically stated, does not include purchases from Western Area Power Administration (Western) or the Calaveras Project operated by NCPA. Additionally, the electricity analysis separates standard bulk power purchases from long-term wind contracts which the City has recently implemented.

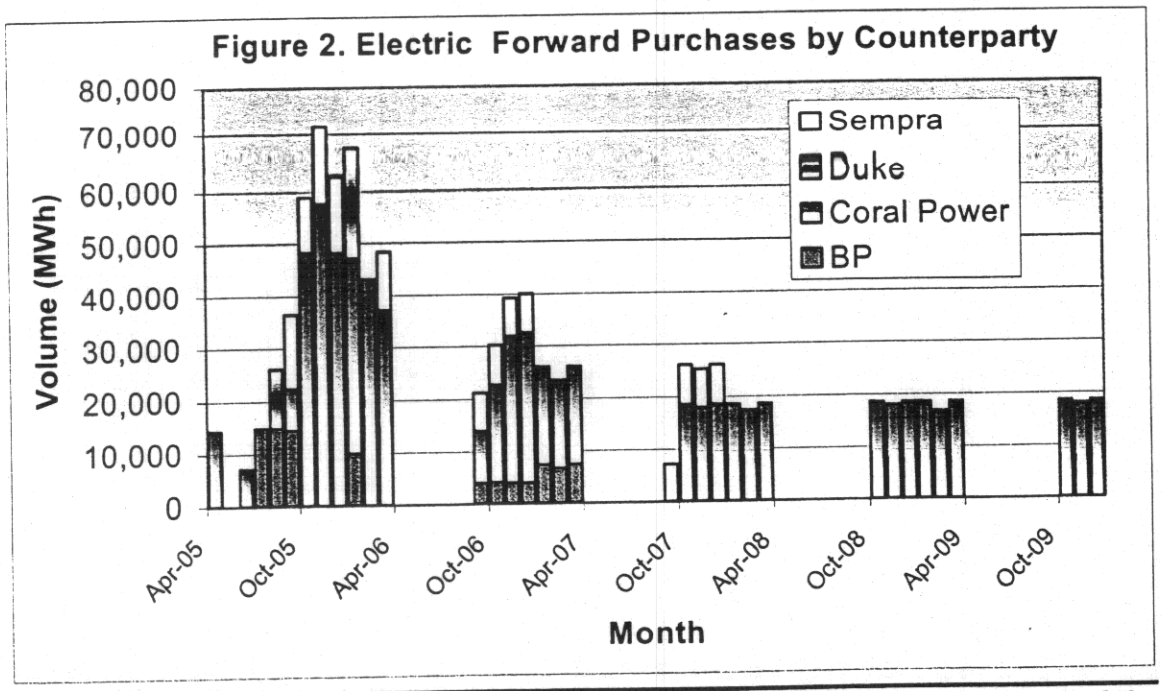
Electricity. As of March 31, 2005 the electric portfolio consisted of 79 open transactions (transactions for which commitments have been made but electricity remains to be delivered) through December 2009. Figure 1 illustrates the sources of electricity supplies by month for the next 36 months. The City currently has purchased supplies of electricity totaling 0.98 million MWh for delivery between January 1, 2005 and December 31, 2009. The average price for all of the fixed-price purchases was $46.38 per MWh, up from $45.81 last quarter. The forward purchases have been transacted with four approved counterparties: Coral Energy, Duke Energy, Sempra Energy and British Petroleum. Note that in Figure 1, the Seattle City Light (SCL) volumes represent a "swap" whereby Palo Alto supplies power to Seattle City Light in the winter

months and Seattle provides power to Palo Alto during the summer months. The distribution of purchases by month and by counterparty is presented in Figure 2.

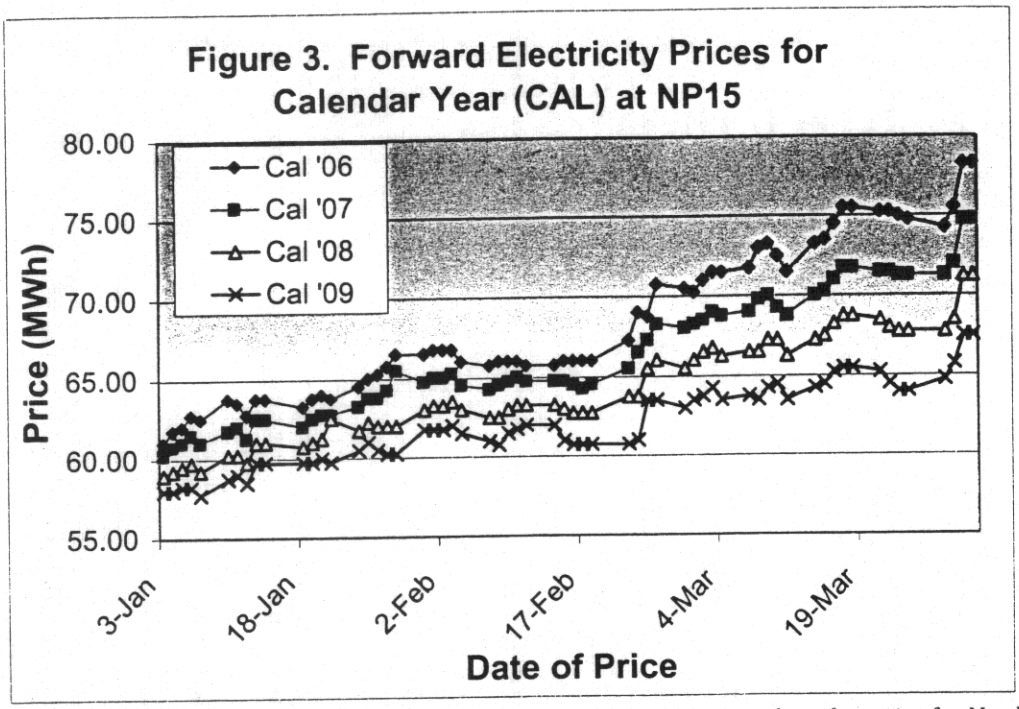
Figure 1.



The Mark to Market (MTM) value represents the difference in price between the current market value of the contracted supply and the original contracted price. A positive MTM value indicates an increase in the value of the purchase, which would be realized only if the transaction was



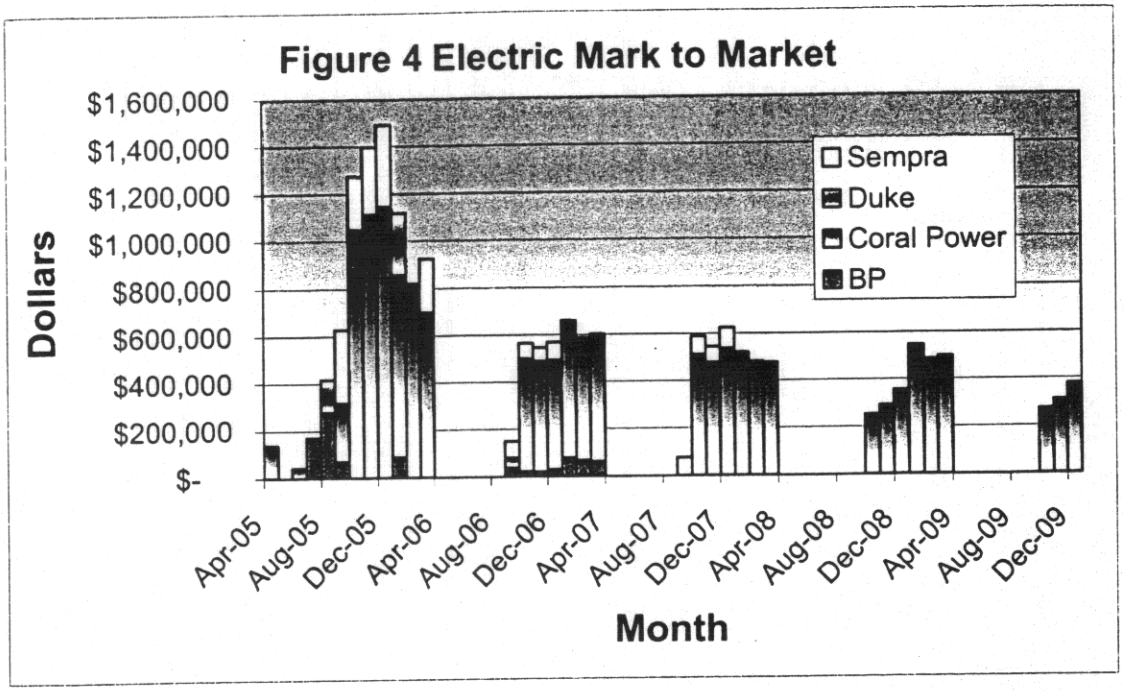
liquidated. While a positive MTM value represents an increase in value to the City, it also represents the City's credit exposure with the supplier. In other words, should a counterparty default on delivery of supply, the City would need to purchase replacement energy on the open market when prices could be higher. A negative MTM represents the supplier's credit exposure with the City.



Note: NP15 refers to North Path 15 which serves as the key delivery and market point for Northern California. As such it represents an aggregated price for the region.

The MTM value is based on the current forward prices, that is the prices at the end of the quarter for deliveries in the future. During the quarter, prices for deliveries in Calendar Years 2006, 2007 2008 and 2009 all increased significantly (Figure 3). As a result, the total MTM value of the City's forward transactions has increased by 74% during the quarter from $10.7 million to $18.7 million. Figure 4 presents the Mark to Market positions for each supplier by month.

Hydro Power. In past reports, the values for the variable quantity purchases, in particular the hydro power contract, have not been reported. Recently, implementation of improvements in the City's transaction reporting systems has facilitated staff inclusion of these contracts into quarterly reports. Based on forecasts provided by Western and the Calaveras Project, and forward market projections, staff has calculated values for these contracts. It should be noted that for both the Western and Calaveras, values are based on the expected volumes of delivery for the next 24 months. These values will change as actual volumes differ from those predicted at this moment. At present, the value through December 2006 is $ 32.9 million for Western, and $ 1.9 million for Calaveras.

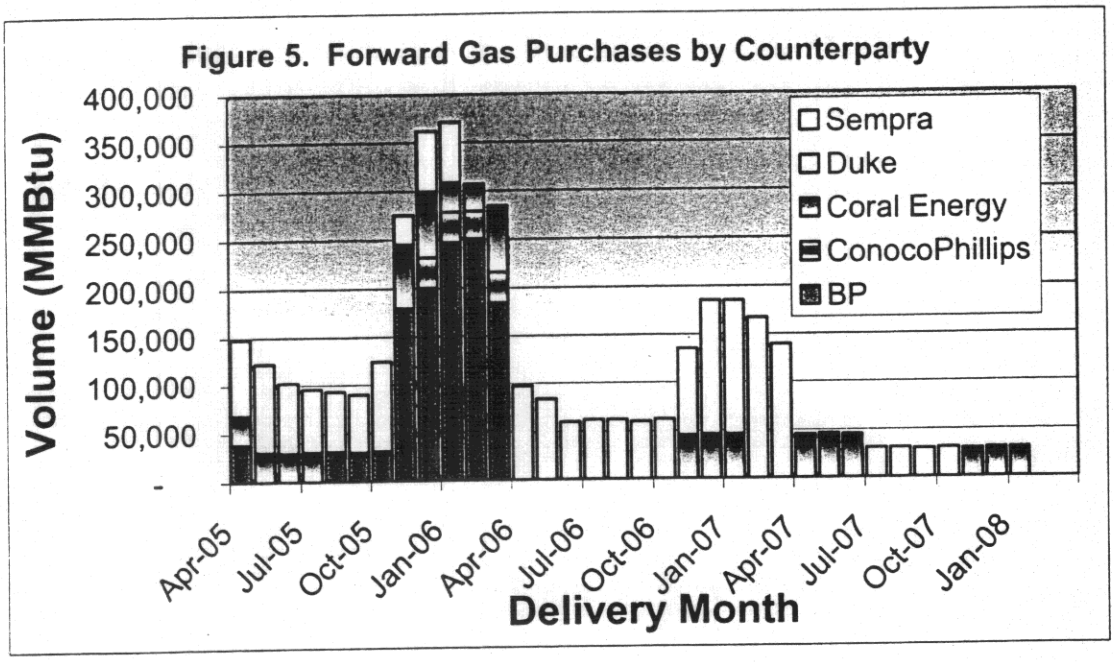


Seasonal Exchange Contracts. The sole seasonal exchange transaction in which Palo Alto is engaged involves Seattle City Light. Under this contract, which was signed in 1992, Palo Alto receives 9 MW from November through March, and sends 10 MW from June through October. The Mark to Market Value of this contract is approximately minus $46,000 per year.

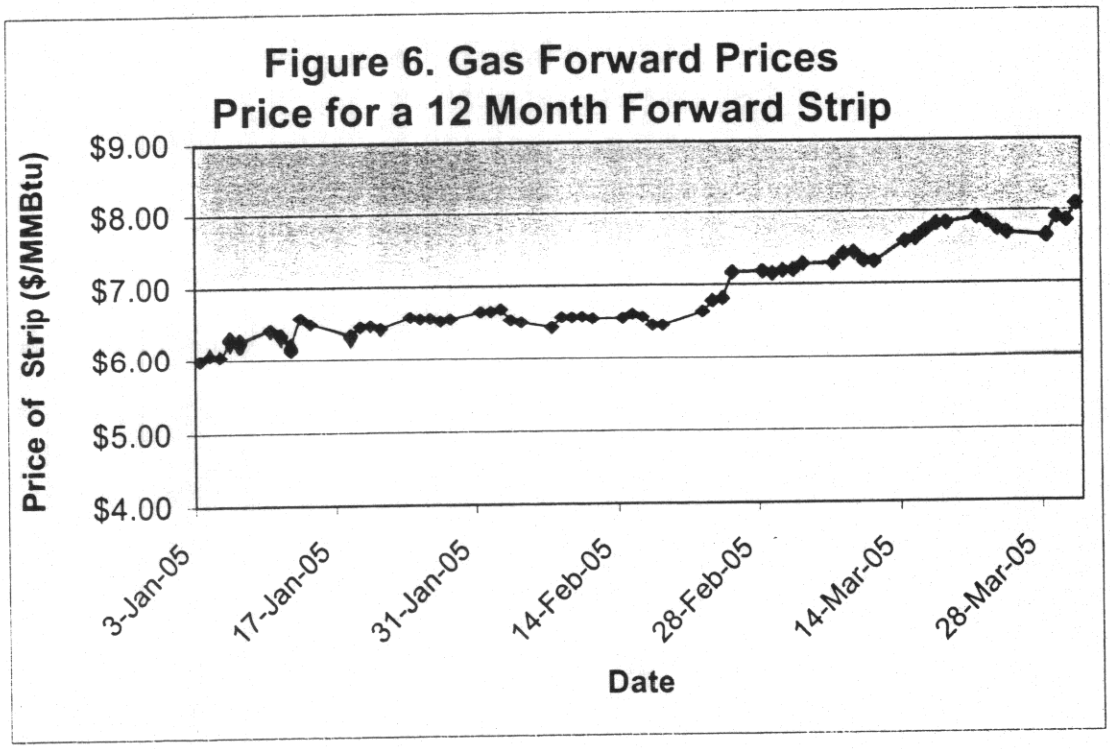
Wind Power. As noted in the previous report, the City recently signed a 23.5-year contract with Pacificorp Power Marketing (PPM) for supplies of wind energy. Wind power has different characteristics from a normal power purchase because it is not volumetrically firm. The amount Palo Alto receives directly relates to how strongly the wind blows. Based on historic meteorological conditions Palo Alto expects to receive approximately 58,000 MWh per year.

Using the expected monthly volume averages for on-peak and off-peak, the MTM value of the contract is a $1.04 million over the next 36 months. This MTM value however, does not include the value of the Renewable Energy Credits associated with the production of the power. These Credits have a variable value of between $2 and $12, but currently their market price is roughly $2.50 for 1 MWh blocks. The additional value of the Credits puts the total MTM value of the contract at an estimated at $1.4 million, compared to a negative $209,000 for last quarter.

Natural Gas. As of December 31, 2004 the gas portfolio consisted of 112 open transactions (transactions for which commitments have been made but gas has yet to be delivered) over the next 36 months. The contract volume of these transactions is 4.0 million MMBtu, with total commitments of $21.60 million and an average price of $5.37 per MMBtu up from $5.19 last quarter. The open commitments for natural gas by month and by supplier are presented in Figure 5.



Forward prices for gas increased by as much as 30% over the quarter (Figure 6).



The current MTM value of these transactions is $ 5.69 million, an increase of 72% from last quarter. The MTM value by month and by counterparty is presented in Figure 7.

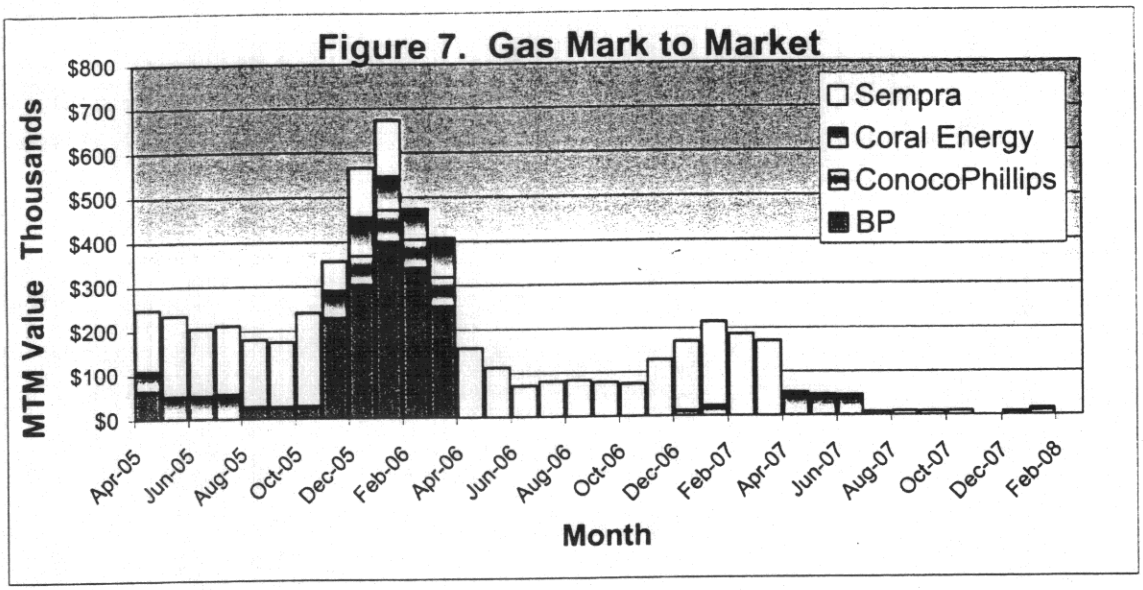
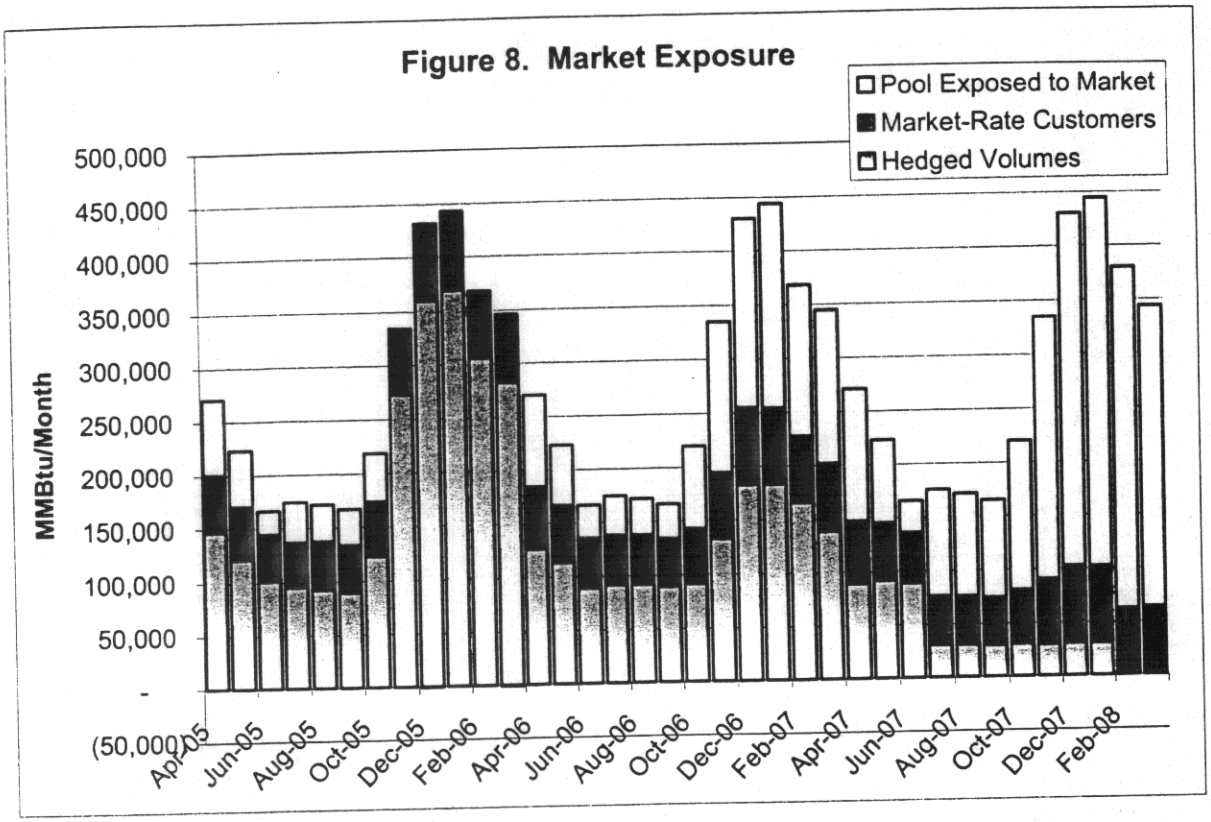


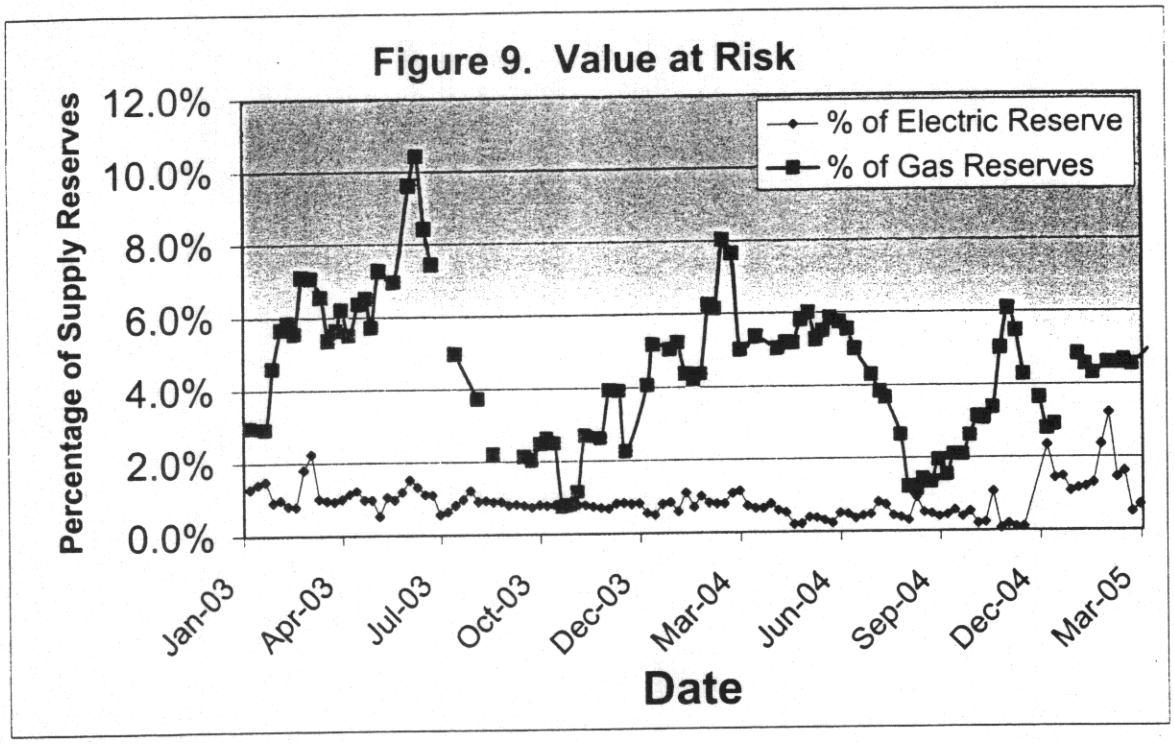
Figure 8 below presents the pool purchases made for each month over the next three years compared to estimated pool load. It illustrates the gas laddering purchasing strategy in relation to the total estimated load, showing the amount of volumes purchased (hedged volumes), the volume to be used by market-rate customers, and the amount of pool to be purchased on the short-term market (pool exposed to market). Under the laddering strategy, CPAU purchases up to 100% of forecasted load for the upcoming 18 months, up to 75% of load for 9 months to 29 months out, and up to 50% of load for 27 to 36 months out. As a result, the amount of pool exposure to the market is low in the near term, but increases further out in the future.



Value at Risk

The "riskiness" of the energy portfolio is measured through the "value at risk" (or VaR). The VaR measures the risk that adverse market conditions could force CPAU to use reserves to cover costs on future purchases over what is reflected in current rates. Specifically, VaR measures how much projected 12-month net revenue could change in one-week due to a potential market change. Staff use the VaR as one of the key measures of risk to the City.

In compliance with the Risk Management Guidelines, the Utilities staff and the Energy Risk Manager monitor the VaR and ensure that its value remains below 10% of the projected end of year supply Rate Stabilization Reserve (RSR) levels for both electricity and gas. Currently, the VaR for the electricity portfolio is 0.70% of the RSR, an increase from 0.13% from last quarter. This is due to increasing forward prices of electricity combined with lowered forecasts for hydro power delivery. The VaR for the gas portfolio is 4.9% of the RSR compared to 4.3% from the previous quarter, as a result of higher forward prices. The historic levels of the VaR values for electricity and gas are presented in Figure 9. Please note that in Figure 9, gaps in the graph indicate missing data.



Credit Risk

Staff has enhanced the City's credit oversight policies and procedures. As part of this process, staff will regularly report on major credit rating agency's (S&P and Moody's) scores, and, in addition, the "estimated default frequency" (EDF) using the Moody's KMV CreditEdge© system. The EDF is an estimated probability that counterparty will default in the next 12 months. For example, a 0.2 EDF indicates a chance of 2 in 1000 that the firm will be in default in the time period. Thus a higher EDF represents a higher credit risk for the City. While the current risk management practices do not set a specific EDF upper limit, any counterparty with a value over 0.50 warrants careful and regular monitoring of its financial condition and outlook.

Electricity. Currently, CPAU's electric supplier counterparty credit exposure and the supplier credit ratings are as follows:

Electricity Suppliers – Credit Exposure and Credit Ratings

Counterparty	Credit Exposure	S&P Ranking	Previous Quarter Expected Default Frequency	Current Expected Default Frequency
BP	$922,174	AA+	.02	.02
Coral	$15,496,789	A-	.03	.02*
Duke	$400,093	BBB	.41	.23
Sempra	$1,961,591	BBB+	.28	.22
Total	$18,780,591			

**Coral is owned by Shell (70%) and Intergen (30%). Intergen is owned by Shell (50%) and Bechtel (50%).*

CPAU's largest exposure, in excess of $15 million, is with an A- rated company with a 0.02 percent default rate. While this exposure is relatively large, the counterparty is financially strong and rated highly by rating agencies.

Renewable Electricity . Palo Alto's contracts for renewable "green" energy include both wind contracts with Pacificorp Power Marketing (PPM), discussed above, as well as contracts to convert landfill gas to electricity with Ameresco, Inc. Neither PPM (owned by Scottish Power) nor Ameresco are publicly traded and therefore KMV Credit Edge does not include them in its default reporting. The Risk Manager therefore has used financial information provided confidentially by each of the two counterparties to estimate an Expected Default Frequency, which is statistically comparable to the EDF's reported for the other counterparties. The Credit Exposure and EDF ratings for these counterparties are presented below.

Green Energy Credit Exposure and Credit Ratings

Counterparty	Credit Exposure	Previous Quarter Calculated Expected Default Frequency	Current Calculated Expected Default Frequency
Ameresco, Inc.	$ 0	N/A	0.85
Pacificorp Power Marketing	$1,400,000	N/A	0.50

Natural Gas. As the next table shows, the City has exposure to five counterparties totaling $5.7 million over the next 36 months. This total is up $2.4 million from last quarter. The highest exposure with a single supplier is $1.96 million with a BBB+ company, with the second highest being with BP at $1.7 million. The remainder of the exposure is distributed between two other counterparties.

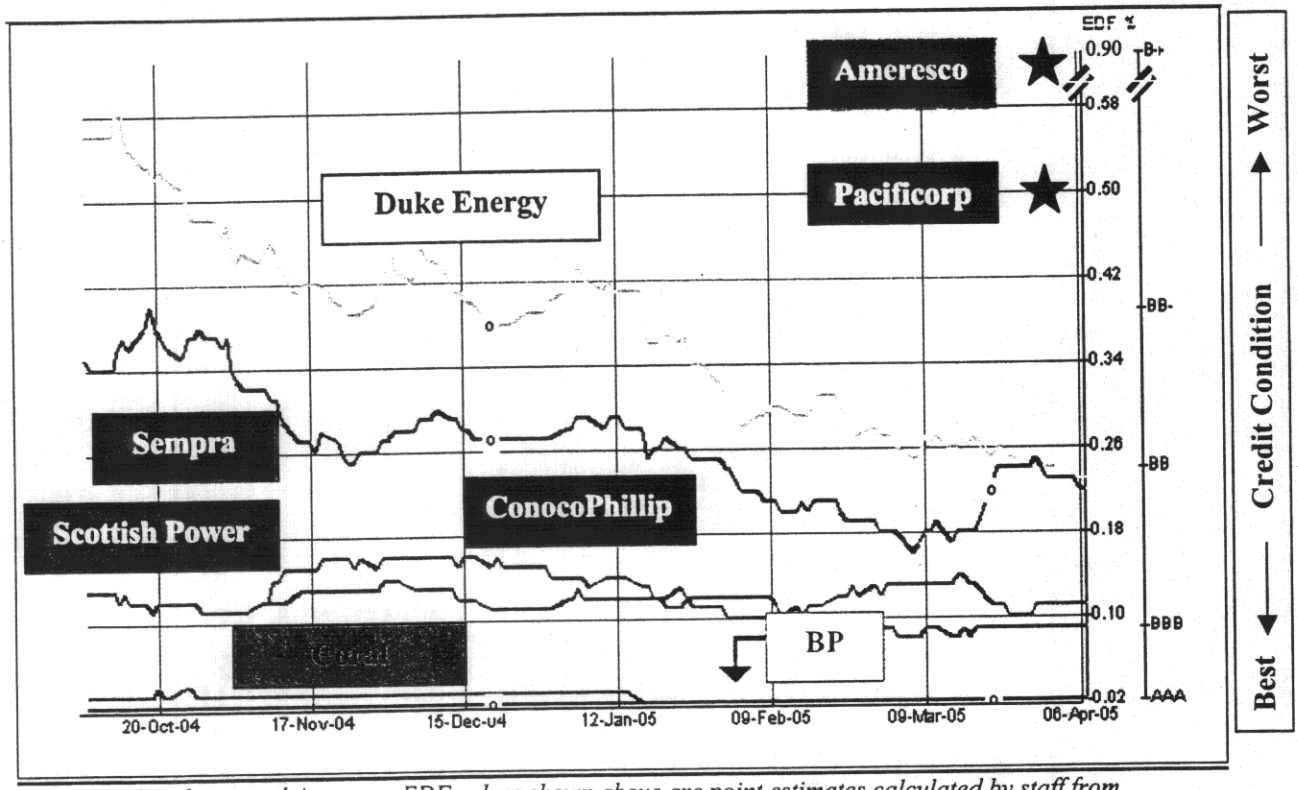
Gas Supplier Credit Exposure and Credit Rating

Counterparty	Credit Exposure	S&P Ranking	Previous Quarter Expected Default Frequency	Current Expected Default Frequency
BP	$ 1,676,970	AA+	.02	.02
ConocoPhillips	$ 263,782	A-	.02	.02
Coral	$ 804,519	A-	.03*	.02
Duke	$ 0	BBB	.41	.23
Sempra	$2,951,682	BBB+	.28	.22
Total	$5,696,953			

**Coral is owned by Shell (70%) and Intergen (30%). Intergen is owned by Shell (50%) and Bechtel (50%).*

Credit Quality of Suppliers. Overall, the City's suppliers have continued to improve their credit quality. Figure 10 shows how the EDF of CPAU's current suppliers has declined (i.e. improved credit) over the past three years. As mentioned previously, Pacificorp Power Marketers is privately held and therefore an EDF is not issued by Moody's KMV. The firm's sole owner Scottish Power is used as a surrogate EDF. Also note that the staff calculated EDF estimates for Pacificorp Power Markets and Ameresco are included on the Figure.

Figure 10. Expected Default Frequencies for CPAU Counterparties over last 90 Trading Days



Note: The Pacificorp and Ameresco EDF values shown above are point estimates calculated by staff from confidential financial information. As such, tracking is done on a quarterly basis and is not continuous.

SUMMARY

Staff has continued to purchase electricity and gas in full accordance with the City's Energy Risk Management Policies and Procedures, and no exceptions have occurred. The average prices paid for both electricity and gas have increased, due to increasing prices in the marketplace. The current value of the City's fixed price purchases is $18.8 million for electricity, up from $10.7 million at the end of last quarter, and $5.7 million for gas, up from $3.3 million at the end of last quarter. The current value of the City's wind power contracts have increased from a negative $209,000 to a positive $1.4 million. All of these increases in value are primarily due to the increase in prices for commodities in the forward markets. The City's Value at Risk measures, an estimate of the risk of the unpurchased portion of the expected load, increased marginally for both gas and electricity and both are well below maximum limits. Corresponding to the changes in portfolio market value, the total credit exposure of the City has increased to $18.8 million for electricity and $5.7 million for gas. The credit ratings of the City's counterparties have again improved, as measured by the Expected Default Frequency.

ATTACHMENTS:

A) Consolidated Mark to Market Report of All Open Gas Transactions as of March 31, 2005
B) Consolidated Mark to Market Report of All Open Electric Transactions as of March 31, 2005

PREPARED BY: _____

KARL VAN ORSDOL
Energy Risk Manager

DEPARTMENT HEAD APPROVAL: _____

CARL YEATS
Director, Administrative Services

CITY MANAGER APPROVAL: _____

EMILY HARRISON
Assistant City Manager

ITEM 5

Appendix A
Gas Transaction Report
March 31, 2005

Counterparty	Delivery Point	Delivery Period	Daily Volume MMBtu	Price	Days In Month	Price Structure	End Use	Total Cost	Deal Type	Total Volume MMBTU	Market Price	Mark to Market
BP	Malin	Apr-05	1,300	$ 4.53	30	Fixed	Pool	$ 176,670.01	Purchase	39,000.00	6.1875	$ 64,642.49
Coral Energy	Malin	Apr-05	1,000	$ 4.66	30	Fixed	Pool	$ 139,800.00	Purchase	30,000.00	6.1875	$ 45,825.00
Sempra	CG	Apr-05	150	$ 5.72	30	Fixed	G11	$ 25,740.00	Purchase	4,500.00	6.1875	$ 2,103.75
Sempra	Malin	Apr-05	1,000	$ 3.92	30	Fixed	Pool	$ 117,600.00	Purchase	30,000.00	6.1875	$ 68,025.00
Sempra	Malin	Apr-05	1,500	$ 4.68	30	Fixed	Pool	$ 210,599.99	Purchase	45,000.00	6.1875	$ 67,837.51
Coral Energy	Malin	May-05	1,000	$ 4.66	31	Fixed	Pool	$ 144,460.00	Purchase	31,000.00	6.3975	$ 53,862.50
Sempra	Malin	May-05	1,000	$ 3.92	31	Fixed	Pool	$ 121,520.00	Purchase	31,000.00	6.3975	$ 76,802.50
Sempra	Malin	May-05	1,800	$ 4.68	31	Fixed	Pool	$ 261,143.99	Purchase	55,800.00	6.3975	$ 95,836.51
Sempra	Malin	May-05	160	$ 4.78	31	Fixed	G11	$ 23,708.80	Purchase	4,960.00	6.3975	$ 8,022.80
Coral Energy	Malin	Jun-05	1,000	$ 4.66	30	Fixed	Pool	$ 139,800.00	Purchase	30,000.00	6.4575	$ 53,925.00
Sempra	Malin	Jun-05	1,000	$ 3.92	30	Fixed	Pool	$ 117,600.00	Purchase	30,000.00	6.4575	$ 76,125.00
Sempra	Malin	Jun-05	1,300	$ 4.68	30	Fixed	Pool	$ 182,519.99	Purchase	39,000.00	6.4575	$ 69,322.51
Sempra	Malin	Jun-05	110	$ 4.78	30	Fixed	G11	$ 15,774.00	Purchase	3,300.00	6.4575	$ 5,535.75
Coral Energy	Malin	Jul-05	1,000	$ 4.66	31	Fixed	Pool	$ 144,460.00	Purchase	31,000.00	6.5175	$ 57,582.50
Sempra	Malin	Jul-05	1,000	$ 3.92	31	Fixed	Pool	$ 121,520.00	Purchase	31,000.00	6.5175	$ 80,522.50
Sempra	Malin	Jul-05	1,000	$ 4.29	31	Fixed	Pool	$ 132,990.00	Purchase	31,000.00	6.5175	$ 69,052.50
Sempra	Malin	Jul-05	90	$ 4.78	31	Fixed	G11	$ 13,336.20	Purchase	2,790.00	6.5175	$ 4,847.62
BP	Malin	Aug-05	1,008	$ 5.63	31	Fixed	Pool	$ 175,863.74	Purchase	31,248.00	6.5425	$ 28,576.30
Sempra	Malin	Aug-05	1,000	$ 3.92	31	Fixed	Pool	$ 121,520.00	Purchase	31,000.00	6.5425	$ 81,297.50
Sempra	Malin	Aug-05	1,000	$ 4.29	31	Fixed	Pool	$ 132,990.00	Purchase	31,000.00	6.5425	$ 69,827.50
BP	Malin	Sep-05	1,008	$ 5.63	30	Fixed	Pool	$ 170,190.71	Purchase	30,240.00	6.5455	$ 27,745.21
Sempra	Malin	Sep-05	1,000	$ 3.92	30	Fixed	Pool	$ 117,600.00	Purchase	30,000.00	6.5455	$ 78,765.00
Sempra	Malin	Sep-05	1,000	$ 4.29	30	Fixed	Pool	$ 128,700.00	Purchase	30,000.00	6.5455	$ 67,665.00
BP	Malin	Oct-05	1,008	$ 5.63	31	Fixed	Pool	$ 175,863.74	Purchase	31,248.00	6.5675	$ 29,357.50
Sempra	Malin	Oct-05	1,000	$ 3.92	31	Fixed	Pool	$ 121,520.00	Purchase	31,000.00	6.5675	$ 82,072.50
Sempra	Malin	Oct-05	1,000	$ 4.29	31	Fixed	Pool	$ 132,990.00	Purchase	31,000.00	6.5675	$ 70,602.50
Sempra	Malin	Oct-05	1,000	$ 4.68	31	Fixed	Pool	$ 145,079.99	Purchase	31,000.00	6.5675	$ 58,512.51
BP	CG	Nov-05	1,000	$ 7.05	30	Fixed	Pool	$ 211,649.99	Purchase	30,000.00	7.241	$ 5,580.01
BP	CG	Nov-05	1,000	$ 6.55	30	Fixed	Pool	$ 196,500.01	Purchase	30,000.00	7.241	$ 20,729.99
BP	Malin	Nov-05	1,008	$ 5.63	30	Fixed	Pool	$ 170,190.71	Purchase	30,240.00	6.848	$ 36,892.81
BP	Malin	Nov-05	2,500	$ 4.73	30	Fixed	Pool	$ 354,750.00	Purchase	75,000.00	6.848	$ 158,850.00
BP	Malin	Nov-05	462	$ 6.36	30	Fixed	Pool	$ 88,080.30	Purchase	13,860.00	6.848	$ 6,832.98
Coral Energy	CG	Nov-05	1,200	$ 7.09	30	Fixed	Pool	$ 255,240.01	Purchase	36,000.00	7.241	$ 5,435.99
Coral Energy	Malin	Nov-05	1,000	$ 4.98	30	Fixed	Pool	$ 149,400.00	Purchase	30,000.00	6.848	$ 56,040.00
Sempra	Malin	Nov-05	1,000	$ 4.68	30	Fixed	Pool	$ 140,399.99	Purchase	30,000.00	6.848	$ 65,040.01
BP	CG	Dec-05	1,000	$ 7.05	31	Fixed	Pool	$ 218,704.99	Purchase	31,000.00	7.608	$ 17,143.01
BP	CG	Dec-05	1,000	$ 6.55	31	Fixed	Pool	$ 203,050.01	Purchase	31,000.00	7.608	$ 32,797.99
BP	CG	Dec-05	1,500	$ 6.54	31	Fixed	Pool	$ 304,110.00	Purchase	46,500.00	7.608	$ 49,662.00
BP	Malin	Dec-05	2,500	$ 4.73	31	Fixed	Pool	$ 366,575.00	Purchase	77,500.00	7.202	$ 191,580.00
BP	Malin	Dec-05	462	$ 6.36	31	Fixed	Pool	$ 91,016.31	Purchase	14,322.00	7.202	$ 12,130.73
ConocoPhillips	Malin	Dec-05	1,008	$ 5.15	31	Fixed	Pool	$ 160,927.20	Purchase	31,248.00	7.202	$ 64,120.89

ITEM 5

Appendix A
Gas Transaction Report
March 31, 2005

Counterparty	Delivery Point	Delivery Period	Daily Volume MMBtu	Price	Days In Month	Price Structure	End Use	Total Cost	Deal Type	Total Volume MMBTU	Market Price	Mark to Market
Coral Energy	CG	Dec-05	1,200	$ 7.09	31	Fixed	Pool	$ 263,748.01	Purchase	37,200.00	7.608	$ 19,269.59
Coral Energy	Malin	Dec-05	1,000	$ 4.98	31	Fixed	Pool	$ 154,380.00	Purchase	31,000.00	7.202	$ 68,882.00
Sempra	CG	Dec-05	1,000	$ 6.56	31	Fixed	Pool	$ 203,344.51	Purchase	31,000.00	7.608	$ 32,503.49
Sempra	Malin	Dec-05	1,000	$ 4.68	31	Fixed	Pool	$ 145,079.99	Purchase	31,000.00	7.202	$ 78,182.01
BP	CG	Jan-06	1,500	$ 6.77	31	Fixed	Pool	$ 314,805.00	Purchase	46,500.00	7.843	$ 49,894.50
BP	CG	Jan-06	1,000	$ 7.05	31	Fixed	Pool	$ 218,704.99	Purchase	31,000.00	7.843	$ 24,428.01
BP	CG	Jan-06	1,000	$ 6.55	31	Fixed	Pool	$ 203,050.01	Purchase	31,000.00	7.843	$ 40,082.99
BP	CG	Jan-06	1,500	$ 6.54	31	Fixed	Pool	$ 304,110.00	Purchase	46,500.00	7.843	$ 60,589.50
BP	Malin	Jan-06	2,500	$ 4.73	31	Fixed	Pool	$ 366,575.00	Purchase	77,500.00	7.434	$ 209,560.00
BP	Malin	Jan-06	462	$ 6.36	31	Fixed	Pool	$ 91,016.31	Purchase	14,322.00	7.434	$ 15,453.44
ConocoPhillips	Malin	Jan-06	1,008	$ 5.15	31	Fixed	Pool	$ 160,927.20	Purchase	31,248.00	7.434	$ 71,370.43
Coral Energy	Malin	Jan-06	1,000	$ 4.98	31	Fixed	Pool	$ 154,380.00	Purchase	31,000.00	7.434	$ 76,074.00
Sempra	CG	Jan-06	1,000	$ 6.56	31	Fixed	Pool	$ 203,344.51	Purchase	31,000.00	7.843	$ 39,788.49
Sempra	Malin	Jan-06	1,000	$ 4.68	31	Fixed	Pool	$ 145,079.99	Purchase	31,000.00	7.434	$ 85,374.01
BP	CG	Feb-06	1,500	$ 6.77	28	Fixed	Pool	$ 284,340.00	Purchase	42,000.00	7.816	$ 43,932.00
BP	CG	Feb-06	2,500	$ 7.54	28	Fixed	Pool	$ 527,800.00	Purchase	70,000.00	7.816	$ 19,320.00
BP	CG	Feb-06	1,000	$ 7.05	28	Fixed	Pool	$ 197,540.00	Purchase	28,000.00	7.816	$ 21,308.00
BP	Malin	Feb-06	1,000	$ 5.43	28	Fixed	Pool	$ 151,900.01	Purchase	28,000.00	7.407	$ 55,495.99
BP	Malin	Feb-06	2,500	$ 4.73	28	Fixed	Pool	$ 331,100.00	Purchase	70,000.00	7.407	$ 187,390.00
BP	Malin	Feb-06	462	$ 6.36	28	Fixed	Pool	$ 82,208.28	Purchase	12,936.00	7.407	$ 13,608.67
ConocoPhillips	Malin	Feb-06	1,008	$ 5.15	28	Fixed	Pool	$ 145,353.60	Purchase	28,224.00	7.407	$ 63,701.57
Coral Energy	Malin	Feb-06	1,000	$ 4.98	28	Fixed	Pool	$ 139,440.00	Purchase	28,000.00	7.407	$ 67,956.00
BP	CG	Mar-06	1,000	$ 7.05	31	Fixed	Pool	$ 218,704.99	Purchase	31,000.00	7.633	$ 17,918.01
BP	CG	Mar-06	1,000	$ 6.55	31	Fixed	Pool	$ 203,050.01	Purchase	31,000.00	7.633	$ 33,572.99
BP	Malin	Mar-06	1,000	$ 7.32	31	Fixed	Pool	$ 226,920.01	Purchase	31,000.00	7.217	$ (3,193.01)
BP	Malin	Mar-06	2,500	$ 4.73	31	Fixed	Pool	$ 366,575.00	Purchase	77,500.00	7.217	$ 192,742.50
BP	Malin	Mar-06	462	$ 6.36	31	Fixed	Pool	$ 91,016.31	Purchase	14,322.00	7.217	$ 12,345.56
ConocoPhillips	Malin	Mar-06	1,008	$ 5.15	31	Fixed	Pool	$ 160,927.20	Purchase	31,248.00	7.217	$ 64,589.61
Coral Energy	CG	Mar-06	1,200	$ 7.09	31	Fixed	Pool	$ 263,748.01	Purchase	37,200.00	7.633	$ 20,199.59
Coral Energy	Malin	Mar-06	1,000	$ 4.98	31	Fixed	Pool	$ 154,380.00	Purchase	31,000.00	7.217	$ 69,347.00
Sempra	Malin	Apr-06	750	$ 4.66	30	Fixed	Pool	$ 104,850.00	Purchase	22,500.00	6.1445	$ 33,401.25
Sempra	Malin	Apr-06	1,000	$ 4.27	30	Fixed	Pool	$ 128,100.00	Purchase	30,000.00	6.1445	$ 56,235.00
Sempra	Malin	Apr-06	1,500	$ 4.65	30	Fixed	Pool	$ 209,250.00	Purchase	45,000.00	6.1445	$ 67,252.50
Sempra	Malin	May-06	1,200	$ 4.66	31	Fixed	Pool	$ 173,351.99	Purchase	37,200.00	6.0045	$ 50,015.41
Sempra	Malin	May-06	1,500	$ 4.65	31	Fixed	Pool	$ 216,225.00	Purchase	46,500.00	6.0045	$ 62,984.25
Sempra	Malin	Jun-06	1,000	$ 4.66	30	Fixed	Pool	$ 139,800.00	Purchase	30,000.00	6.0295	$ 41,085.00
Sempra	Malin	Jun-06	1,000	$ 5.06	30	Fixed	Pool	$ 151,785.01	Purchase	30,000.00	6.0295	$ 29,099.99
Sempra	Malin	Jul-06	1,000	$ 5.06	31	Fixed	Pool	$ 156,844.51	Purchase	31,000.00	6.0595	$ 30,999.99
Sempra	Malin	Jul-06	1,000	$ 4.48	31	Fixed	Pool	$ 138,880.00	Purchase	31,000.00	6.0595	$ 48,964.50
Sempra	Malin	Aug-06	1,000	$ 5.06	31	Fixed	Pool	$ 156,844.51	Purchase	31,000.00	6.0895	$ 31,929.99
Sempra	Malin	Aug-06	1,000	$ 4.48	31	Fixed	Pool	$ 138,880.00	Purchase	31,000.00	6.0895	$ 49,894.50

Appendix A
Gas Transaction Report
March 31, 2005

Counterparty	Delivery Point	Delivery Period	Daily Volume MMBtu	Price	Days In Month	Price Structure	End Use	Total Cost	Deal Type	Total Volume MMBTU	Market Price	Mark to Market
Sempra	Malin	Sep-06	1,000	$ 5.06	30	Fixed	Pool	$ 151,785.01	Purchase	30,000.00	6.0645	$ 30,149.99
Sempra	Malin	Sep-06	1,000	$ 4.48	30	Fixed	Pool	$ 134,400.00	Purchase	30,000.00	6.0645	$ 47,535.00
Sempra	Malin	Oct-06	2,000	$ 4.89	31	Fixed	Pool	$ 303,490.00	Purchase	62,000.00	6.0845	$ 73,749.00
Coral Energy	Malin	Nov-06	1,500	$ 6.34	30	Fixed	Pool	$ 285,524.99	Purchase	45,000.00	6.357	$ 540.01
Sempra	Malin	Nov-06	2,000	$ 4.89	30	Fixed	Pool	$ 293,700.00	Purchase	60,000.00	6.357	$ 87,720.00
Sempra	Malin	Nov-06	1,000	$ 5.03	30	Fixed	Pool	$ 150,900.01	Purchase	30,000.00	6.357	$ 39,809.99
Coral Energy	Malin	Dec-06	1,500	$ 6.34	31	Fixed	Pool	$ 295,042.49	Purchase	46,500.00	6.627	$ 13,113.01
Sempra	Malin	Dec-06	2,000	$ 4.89	31	Fixed	Pool	$ 303,490.00	Purchase	62,000.00	6.627	$ 107,384.00
Sempra	Malin	Dec-06	1,000	$ 5.03	31	Fixed	Pool	$ 155,930.01	Purchase	31,000.00	6.627	$ 49,506.99
Sempra	Malin	Dec-06	1,470	$ 6.64	31	Fixed	Pool	$ 302,584.79	Purchase	45,570.00	6.627	$ (592.40)
Coral Energy	Malin	Jan-07	1,500	$ 6.34	31	Fixed	Pool	$ 295,042.49	Purchase	46,500.00	6.867	$ 24,273.01
Sempra	Malin	Jan-07	2,000	$ 4.89	31	Fixed	Pool	$ 303,490.00	Purchase	62,000.00	6.867	$ 122,264.00
Sempra	Malin	Jan-07	1,000	$ 5.03	31	Fixed	Pool	$ 155,930.01	Purchase	31,000.00	6.867	$ 56,946.99
Sempra	Malin	Jan-07	1,470	$ 6.64	31	Fixed	Pool	$ 302,584.79	Purchase	45,570.00	6.867	$ 10,344.40
Sempra	Malin	Feb-07	1,500	$ 6.39	28	Fixed	Pool	$ 268,170.01	Purchase	42,000.00	6.832	$ 18,773.99
Sempra	Malin	Feb-07	2,000	$ 4.89	28	Fixed	Pool	$ 274,120.00	Purchase	56,000.00	6.832	$ 108,472.00
Sempra	Malin	Feb-07	1,000	$ 5.03	28	Fixed	Pool	$ 140,840.01	Purchase	28,000.00	6.832	$ 50,455.99
Sempra	Malin	Feb-07	1,470	$ 6.64	28	Fixed	Pool	$ 273,302.39	Purchase	41,160.00	6.832	$ 7,902.73
Sempra	Malin	Mar-07	1,500	$ 6.39	31	Fixed	Pool	$ 296,902.51	Purchase	46,500.00	6.637	$ 11,717.99
Sempra	Malin	Mar-07	2,000	$ 4.89	31	Fixed	Pool	$ 303,490.00	Purchase	62,000.00	6.637	$ 108,004.00
Sempra	Malin	Mar-07	1,000	$ 5.03	31	Fixed	Pool	$ 155,930.01	Purchase	31,000.00	6.637	$ 49,816.99
Coral Energy	Malin	Apr-07	1,500	$ 4.63	30	Fixed	Pool	$ 208,350.01	Purchase	45,000.00	5.817	$ 53,414.99
Coral Energy	Malin	May-07	1,500	$ 4.63	31	Fixed	Pool	$ 215,295.01	Purchase	46,500.00	5.657	$ 47,755.49
Coral Energy	Malin	Jun-07	1,500	$ 4.63	30	Fixed	Pool	$ 208,350.01	Purchase	45,000.00	5.667	$ 46,664.99
Sempra	Malin	Jul-07	1,000	$ 5.41	31	Fixed	Pool	$ 167,865.00	Purchase	31,000.00	5.682	$ 8,277.00
Sempra	Malin	Aug-07	1,000	$ 5.41	31	Fixed	Pool	$ 167,865.00	Purchase	31,000.00	5.719	$ 9,424.00
Sempra	Malin	Sep-07	1,000	$ 5.41	30	Fixed	Pool	$ 162,450.00	Purchase	30,000.00	5.709	$ 8,820.00
Sempra	Malin	Oct-07	1,000	$ 5.41	31	Fixed	Pool	$ 167,865.00	Purchase	31,000.00	5.727	$ 9,672.00
Coral Energy	Malin	Nov-07	1,000	$ 6.00	30	Fixed	Pool	$ 180,000.00	Purchase	30,000.00	6.007	$ 210.00
Coral Energy	Malin	Dec-07	1,000	$ 6.00	31	Fixed	Pool	$ 186,000.00	Purchase	31,000.00	6.267	$ 8,277.00
Coral Energy	Malin	Jan-08	1,000	$ 6.00	31	Fixed	Pool	$ 186,000.00	Purchase	31,000.00	6.512	$ 15,872.00
Totals								**$ 21,607,205.15**		**4,026,956.00**		**$ 5,696,953.90**

ITEM 5

Appendix B.
Electric Transaction Quarterly Report
March 31, 2005

Counterparty	Delivery Point	Delivery Period	MW	On Peak Hours	Off Peak Hours	Contract Price per MWh	Deal Type	Heavy Load Hours	Light Load Hours	Total Load Hours	Market Price HLH	Market Price LLH	Total Price	Total Market Value	Mark to Market Value
Coral Power	NP15	Apr-05	10	416	-	$ 53.55	Purch.	4,160	-	4,160	$ 62.25	$ 49.91	$ 222,768	$ 258,960	$ 36,192
Coral Power	NP15	Apr-05	20	416	303	$ 49.75	Purch.	8,320	6,060	14,380	$ 62.25	$ 49.91	$ 715,405	$ 820,358	$ 104,953
Coral Power	NP15	Jun-05	10	416	304	$ 57.00	Purch.	4,160	3,040	7,200	$ 71.00	$ 52.06	$ 410,400	$ 453,632	$ 43,232
BP	NP15	Jul-05	20	400	344	$ 62.50	Purch.	8,000	6,880	14,880	$ 85.75	$ 60.37	$ 930,000	$ 1,101,380	$ 171,380
Duke	NP15	Aug-05	15	432	312	$ 68.50	Purch.	6,480	4,680	11,160	$ 92.52	$ 65.14	$ 764,460	$ 904,392	$ 139,932
BP	NP15	Aug-05	20	432	312	$ 62.50	Purch.	8,640	6,240	14,880	$ 92.52	$ 65.14	$ 930,000	$ 1,205,855	$ 275,855
Sempra	NP15	Sep-05	25	400	-	$ 54.75	Purch.	10,000	-	10,000	$ 77.48	$ 54.55	$ 547,500	$ 774,772	$ 227,272
Sempra	NP15	Sep-05	10	400	-	$ 56.25	Purch.	4,000	-	4,000	$ 77.48	$ 54.55	$ 225,000	$ 309,909	$ 84,909
Coral Power	NP15	Sep-05	25	400	-	$ 69.25	Sale	(10,000)	-	(10,000)	$ 77.48	$ 54.55	$ (692,500)	$ (774,772)	$ (82,272)
Coral Power	COB	Sep-05	25	400	320	$ 47.40	Purch.	10,000	8,000	18,000	$ 72.48	$ 57.18	$ 853,200	$ 1,182,250	$ 329,050
BP	NP15	Sep-05	20	400	320	$ 62.50	Purch.	8,000	6,400	14,400	$ 77.48	$ 54.55	$ 900,000	$ 968,924	$ 68,924
Sempra	NP15	Oct-05	25	416	-	$ 54.75	Purch.	10,400	-	10,400	$ 76.23	$ 60.16	$ 569,400	$ 792,752	$ 223,352
Coral Power	NP15	Oct-05	25	416	329	$ 36.60	Purch.	10,400	8,225	18,625	$ 76.23	$ 60.16	$ 681,675	$ 1,287,602	$ 605,927
Coral Power	NP15	Oct-05	15	416	329	$ 59.65	Purch.	6,240	4,935	11,175	$ 76.23	$ 60.16	$ 666,589	$ 772,561	$ 105,972
Coral Power	COB	Oct-05	25	416	329	$ 47.40	Purch.	10,400	8,225	18,625	$ 70.52	$ 59.15	$ 882,825	$ 1,219,870	$ 337,045
Sempra	NP15	Nov-05	25	400	-	$ 54.75	Purch.	10,000	-	10,000	$ 75.44	$ 59.54	$ 547,500	$ 754,403	$ 206,903
Sempra	NP15	Nov-05	10	400	-	$ 56.25	Purch.	4,000	-	4,000	$ 75.44	$ 59.54	$ 225,000	$ 301,761	$ 76,761
Coral Power	NP15	Nov-05	25	400	320	$ 36.60	Purch.	10,000	8,000	18,000	$ 75.44	$ 59.54	$ 658,800	$ 1,230,754	$ 571,954
Coral Power	NP15	Nov-05	15	400	320	$ 59.65	Purch.	6,000	4,800	10,800	$ 75.44	$ 59.54	$ 644,220	$ 738,453	$ 94,232
Coral Power	NP15	Nov-05	15	400	320	$ 56.00	Purch.	6,000	4,800	10,800	$ 75.44	$ 59.54	$ 604,800	$ 738,453	$ 133,653
Coral Power	COB	Nov-05	25	400	320	$ 47.40	Purch.	10,000	8,000	18,000	$ 69.79	$ 58.54	$ 853,200	$ 1,166,208	$ 313,008
Sempra	NP15	Dec-05	25	416	-	$ 54.75	Purch.	10,400	-	10,400	$ 78.58	$ 62.02	$ 569,400	$ 817,270	$ 247,870
Sempra	NP15	Dec-05	10	416	-	$ 56.25	Purch.	4,160	-	4,160	$ 78.58	$ 62.02	$ 234,000	$ 326,908	$ 92,908
Coral Power	NP15	Dec-05	25	416	328	$ 36.60	Purch.	10,400	8,200	18,600	$ 78.58	$ 62.02	$ 680,760	$ 1,325,874	$ 645,114
Coral Power	NP15	Dec-05	15	416	328	$ 59.65	Purch.	6,240	4,920	11,160	$ 78.58	$ 62.02	$ 665,694	$ 795,524	$ 129,830
Coral Power	COB	Dec-05	25	416	328	$ 47.40	Purch.	10,400	8,200	18,600	$ 72.70	$ 60.98	$ 881,640	$ 1,256,074	$ 374,434
Duke	NP15	Jan-06	25	400	-	$ 66.25	Purch.	10,000	-	10,000	$ 79.26	$ 60.39	$ 662,500	$ 792,581	$ 130,081
Duke	NP15	Jan-06	25	400	-	$ 66.25	Purch.	10,000	-	10,000	$ 79.26	$ 60.39	$ 662,500	$ 792,581	$ 130,081
Coral Power	NP15	Jan-06	25	400	344	$ 36.60	Purch.	10,000	8,600	18,600	$ 79.26	$ 60.39	$ 680,760	$ 1,311,910	$ 631,150
Coral Power	NP15	Jan-06	10	400	344	$ 58.25	Purch.	4,000	3,440	7,440	$ 79.26	$ 60.39	$ 433,380	$ 524,764	$ 91,384
Coral Power	NP15	Jan-06	15	400	344	$ 66.25	Purch.	6,000	5,160	11,160	$ 79.26	$ 60.39	$ 739,350	$ 787,146	$ 47,796
BP	NP15	Jan-06	25	400	-	$ 70.50	Purch.	10,000	-	10,000	$ 79.26	$ 60.39	$ 705,000	$ 792,581	$ 87,581
Coral Power	NP15	Feb-06	25	384	288	$ 36.60	Purch.	9,600	7,200	16,800	$ 78.50	$ 59.81	$ 614,880	$ 1,184,277	$ 569,397
Coral Power	NP15	Feb-06	10	384	288	$ 58.25	Purch.	3,840	2,880	6,720	$ 78.50	$ 59.81	$ 391,440	$ 473,711	$ 82,271
Coral Power	NP15	Feb-06	15	384	288	$ 66.25	Purch.	5,760	4,320	10,080	$ 78.50	$ 59.81	$ 667,800	$ 710,566	$ 42,766

Appendix B.
Electric Transaction Quarterly Report
March 31, 2005

Counterparty	Delivery Point	Delivery Period	MW	On Peak Hours	Off Peak Hours	Contract Price per MWh	Deal Type	Heavy Load Hours	Light Load Hours	Total Load Hours	Market Price HLH	Market Price LLH	Total Price	Total Market Value	Mark to Market Value
Coral Power	NP15	Feb-06	25	384	-	$ 65.50	Purch.	9,600	-	9,600	$ 78.50	$ 59.81	$ 628,800	$ 753,631	$ 124,831
Sempra	NP15	Mar-06	15	432	312	$ 48.50	Purch.	6,480	4,680	11,160	$ 76.24	$ 58.09	$ 541,260	$ 765,872	$ 224,612
Coral Power	NP15	Mar-06	25	432	312	$ 36.60	Purch.	10,800	7,800	18,600	$ 76.24	$ 58.09	$ 680,760	$ 1,276,454	$ 595,694
Coral Power	NP15	Mar-06	10	432	312	$ 58.25	Purch.	4,320	3,120	7,440	$ 76.24	$ 58.09	$ 433,380	$ 510,582	$ 77,202
Coral Power	NP15	Mar-06	15	432	312	$ 66.25	Purch.	6,480	4,680	11,160	$ 76.24	$ 58.09	$ 739,350	$ 765,872	$ 26,522
Sempra	NP15	Sep-06	10	400	320	$ 53.50	Purch.	4,000	3,200	7,200	$ 72.47	$ 51.57	$ 385,200	$ 454,908	$ 69,708
Coral Power	COB	Sep-06	25	400	-	$ 59.50	Purch.	10,000	-	10,000	$ 63.78	$ 51.35	$ 595,000	$ 637,812	$ 42,812
BP	COB	Sep-06	10	400	-	$ 54.50	Purch.	4,000	-	4,000	$ 63.78	$ 51.35	$ 218,000	$ 255,125	$ 37,125
Sempra	NP15	Oct-06	10	416	329	$ 53.50	Purch.	4,160	3,290	7,450	$ 68.25	$ 54.45	$ 398,575	$ 463,043	$ 64,468
Coral Power	NP15	Oct-06	25	416	329	$ 36.60	Purch.	10,400	8,225	18,625	$ 68.25	$ 54.45	$ 681,675	$ 1,157,608	$ 475,933
BP	COB	Oct-06	10	416	-	$ 54.50	Purch.	4,160	-	4,160	$ 60.07	$ 51.41	$ 226,720	$ 249,874	$ 23,154
Sempra	NP15	Nov-06	10	400	320	$ 53.50	Purch.	4,000	3,200	7,200	$ 67.55	$ 53.88	$ 385,200	$ 442,613	$ 57,413
Coral Power	NP15	Nov-06	25	400	320	$ 36.60	Purch.	10,000	8,000	18,000	$ 67.55	$ 53.88	$ 658,800	$ 1,106,531	$ 447,731
Coral Power	COB	Nov-06	25	400	-	$ 57.50	Purch.	10,000	-	10,000	$ 59.45	$ 50.88	$ 575,000	$ 594,466	$ 19,466
BP	COB	Nov-06	10	400	-	$ 54.50	Purch.	4,000	-	4,000	$ 59.45	$ 50.88	$ 218,000	$ 237,786	$ 19,786
Sempra	NP15	Dec-06	10	400	344	$ 53.50	Purch.	4,000	3,440	7,440	$ 70.36	$ 56.13	$ 398,040	$ 474,526	$ 76,486
Coral Power	NP15	Dec-06	25	400	344	$ 36.60	Purch.	10,000	8,600	18,600	$ 70.36	$ 56.13	$ 680,760	$ 1,186,315	$ 505,555
Coral Power	COB	Dec-06	25	400	-	$ 66.25	Purch.	10,000	-	10,000	$ 61.92	$ 53.00	$ 662,500	$ 619,235	$ (43,265)
BP	COB	Dec-06	10	400	-	$ 54.50	Purch.	4,000	-	4,000	$ 61.92	$ 53.00	$ 218,000	$ 247,694	$ 29,694
Coral Power	NP15	Jan-07	25	416	328	$ 36.60	Purch.	10,400	8,200	18,600	$ 75.66	$ 57.81	$ 680,760	$ 1,260,958	$ 580,198
BP	COB	Jan-07	10	416	328	$ 51.50	Purch.	4,160	3,280	7,440	$ 66.47	$ 56.45	$ 383,160	$ 461,649	$ 78,489
Coral Power	NP15	Feb-07	25	384	288	$ 36.60	Purch.	9,600	7,200	16,800	$ 74.94	$ 57.26	$ 614,880	$ 1,131,733	$ 516,853
BP	COB	Feb-07	10	384	288	$ 51.50	Purch.	3,840	2,880	6,720	$ 65.83	$ 55.91	$ 346,080	$ 413,821	$ 67,741
Coral Power	NP15	Mar-07	25	432	312	$ 36.60	Purch.	10,800	7,800	18,600	$ 72.78	$ 55.61	$ 680,760	$ 1,219,790	$ 539,030
BP	COB	Mar-07	10	432	312	$ 51.50	Purch.	4,320	3,120	7,440	$ 63.94	$ 54.30	$ 383,160	$ 445,604	$ 62,444
Sempra	NP15	Sep-07	10	384	336	$ 53.65	Purch.	3,840	3,360	7,200	$ 74.22	$ 52.97	$ 386,280	$ 462,981	$ 76,701
Sempra	NP15	Oct-07	10	432	313	$ 53.65	Purch.	4,320	3,130	7,450	$ 69.90	$ 55.92	$ 399,693	$ 476,991	$ 77,299
Coral Power	NP15	Oct-07	25	432	313	$ 36.60	Purch.	10,800	7,825	18,625	$ 69.90	$ 55.92	$ 681,675	$ 1,192,478	$ 510,803
Sempra	NP15	Nov-07	10	400	320	$ 53.65	Purch.	4,000	3,200	7,200	$ 69.18	$ 55.34	$ 386,280	$ 453,811	$ 67,531
Coral Power	NP15	Nov-07	25	400	320	$ 36.60	Purch.	10,000	8,000	18,000	$ 69.18	$ 55.34	$ 658,800	$ 1,134,527	$ 475,727
Sempra	NP15	Dec-07	10	400	344	$ 53.65	Purch.	4,000	3,440	7,440	$ 72.06	$ 57.65	$ 399,156	$ 486,556	$ 87,400
Coral Power	NP15	Dec-07	25	400	344	$ 36.60	Purch.	10,000	8,600	18,600	$ 72.06	$ 57.65	$ 680,760	$ 1,216,389	$ 535,629
Coral Power	NP15	Jan-08	25	416	328	$ 36.60	Purch.	10,400	8,200	18,600	$ 71.98	$ 55.17	$ 680,760	$ 1,201,042	$ 520,282
Coral Power	NP15	Feb-08	25	400	296	$ 36.60	Purch.	10,000	7,400	17,400	$ 71.30	$ 54.65	$ 636,840	$ 1,117,367	$ 480,527
Coral Power	NP15	Mar-08	25	416	328	$ 36.60	Purch.	10,400	8,200	18,600	$ 69.24	$ 53.07	$ 680,760	$ 1,155,288	$ 474,528

ITEM 5

Appendix B.
Electric Transaction Quarterly Report
March 31, 2005

Counterparty	Delivery Point	Delivery Period	MW	On Peak Hours	Off Peak Hours	Contract Price per MWh	Deal Type	Heavy Load Hours	Light Load Hours	Total Load Hours	Market Price HLH	Market Price LLH	Total Price	Total Market Value	Mark to Market Value
Coral Power	NP15	Oct-08	25	432	313	$ 36.60	Purch.	10,800	7,825	18,625	$ 55.92	$ 42.23	$ 681,675	$ 934,410	$ 252,735
Coral Power	NP15	Nov-08	25	384	336	$ 36.60	Purch.	9,600	8,400	18,000	$ 58.25	$ 46.50	$ 658,800	$ 949,759	$ 290,959
Coral Power	NP15	Dec-08	25	416	328	$ 36.60	Purch.	10,400	8,200	18,600	$ 61.16	$ 48.82	$ 680,760	$ 1,036,413	$ 355,653
Coral Power	NP15	Jan-09	25	416	328	$ 36.60	Purch.	10,400	8,200	18,600	$ 73.42	$ 56.27	$ 680,760	$ 1,225,063	$ 544,303
Coral Power	NP15	Feb-09	25	384	288	$ 36.60	Purch.	9,600	7,200	16,800	$ 72.73	$ 55.74	$ 614,880	$ 1,099,477	$ 484,597
Coral Power	NP15	Mar-09	25	416	328	$ 36.60	Purch.	10,400	8,200	18,600	$ 70.63	$ 54.13	$ 680,760	$ 1,178,393	$ 497,634
Coral Power	NP15	Oct-09	25	432	313	$ 36.60	Purch.	10,800	7,825	18,625	$ 57.04	$ 43.08	$ 681,675	$ 953,098	$ 271,423
Coral Power	NP15	Nov-09	25	384	336	$ 36.60	Purch.	9,600	8,400	18,000	$ 59.42	$ 47.43	$ 658,800	$ 968,755	$ 309,955
Coral Power	NP15	Dec-09	25	416	328	$ 36.60	Purch.	10,400	8,200	18,600	$ 62.39	$ 49.80	$ 680,760	$ 1,057,142	$ 376,382
Totals/Avgs.						**$ 50.14**		**599,280**	**365,725**	**965,005**	**$ 72.04**	**$ 56.13**	**$ 44,753,039**	**$ 63,533,681**	**$ 18,780,643**

TO: **HONORABLE CITY COUNCIL**

FROM: **CITY MANAGER** **DEPARTMENT: ADMINISTRATIVE SERVICES**

DATE: **NOVEMBER 14, 2005** **CMR: 414:05**

SUBJECT: **CITY OF PALO ALTO'S ENERGY RISK MANAGEMENT REPORT FOR THE FIRST QUARTER, FISCAL YEAR 2005-2006**

This is an information report and no action is required.

OVERVIEW

Staff has continued to purchase electricity and gas in full accordance with the City's Energy Risk Management Policies and Procedures, and no exceptions have occurred. The recent rapid increases in prices for both electricity and gas have exerted major impacts of the City's positions. The current value of the City's fixed price purchases is $41.5 million for electricity, up from $19.7 million at the end of last quarter; and $24.0 million for gas, up from $9.0 million at the end of last quarter. The current value of the City's wind power contracts for the next 12 months have increased from $1.4 million to $1.9 million. The value of the hydro contracts with Western and NCPA have increased in value from $24 million to $53 million. All of these increases in value are solely due to the increase in prices for commodities in the forward markets. The electricity VaR measure declined and remain below maximum limits, although the gas VaR is approaching the limit set by the Risk Manager. Corresponding to the changes in portfolio market value, the total credit exposure of the City has increased to $41.5 million for electricity and $24.0 million for gas.

BACKGROUND

The purpose of this report is to inform the City Council of the status of the City's energy portfolio and transactions executed with energy suppliers as of the end of the first quarter of Fiscal Year 2005-06. The City's Energy Risk Management Policy requires that staff report on a quarterly basis to Council on: 1) the City's energy portfolio, 2) the City's credit and market risk profile, 3) portfolio performance, and 4) other key market and risk information.

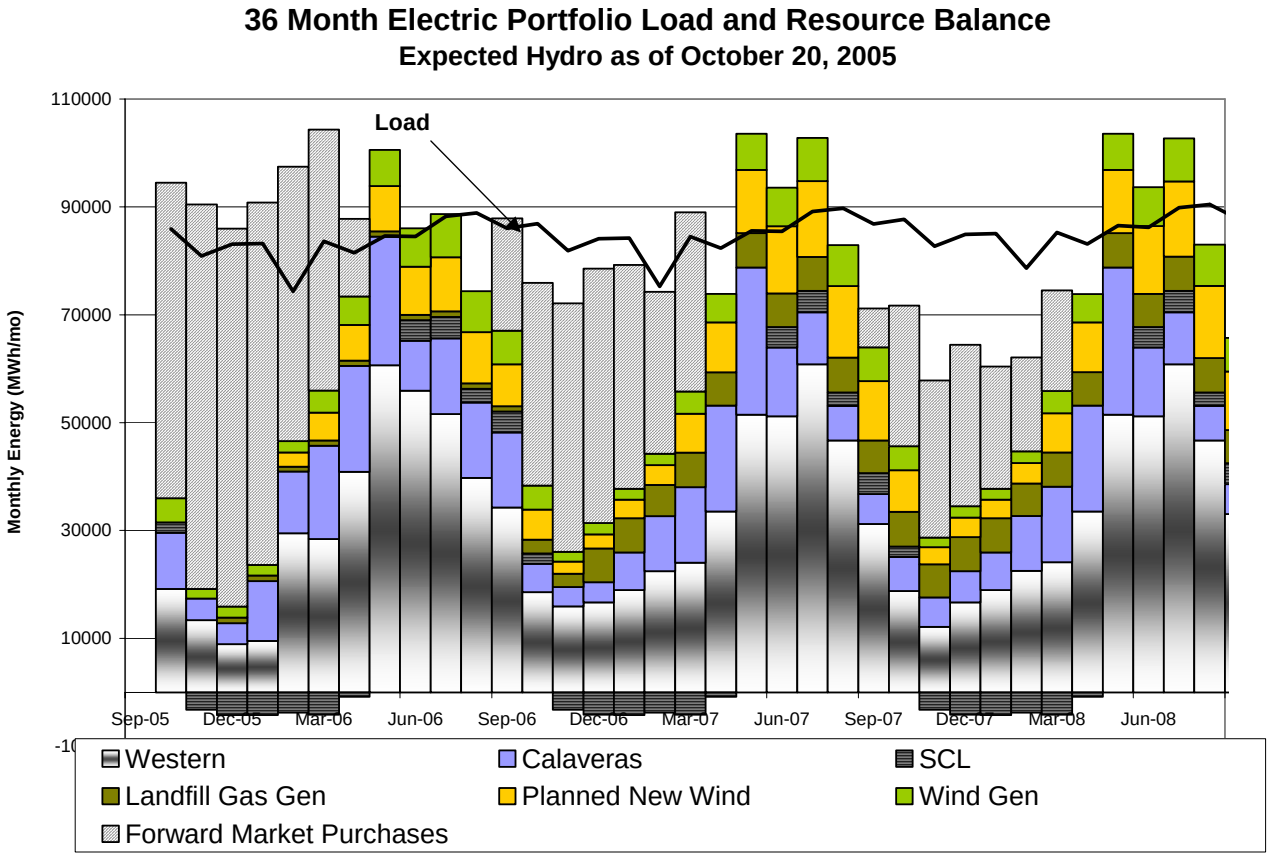
DISCUSSION

Open Transactions as of September 30, 2005

Open transactions are commitments that the City has made to purchase either electricity or gas, but for which supplies have not yet been delivered. The analysis presented here is restricted to forward fixed price purchases with corporate counterparties, and, except where specifically stated, does not include purchases from Western Area Power Administration (Western) or the Calaveras Project operated by NCPA. Additionally, the electricity analysis separates standard bulk power purchases from long-term wind contracts which the City has recently implemented.

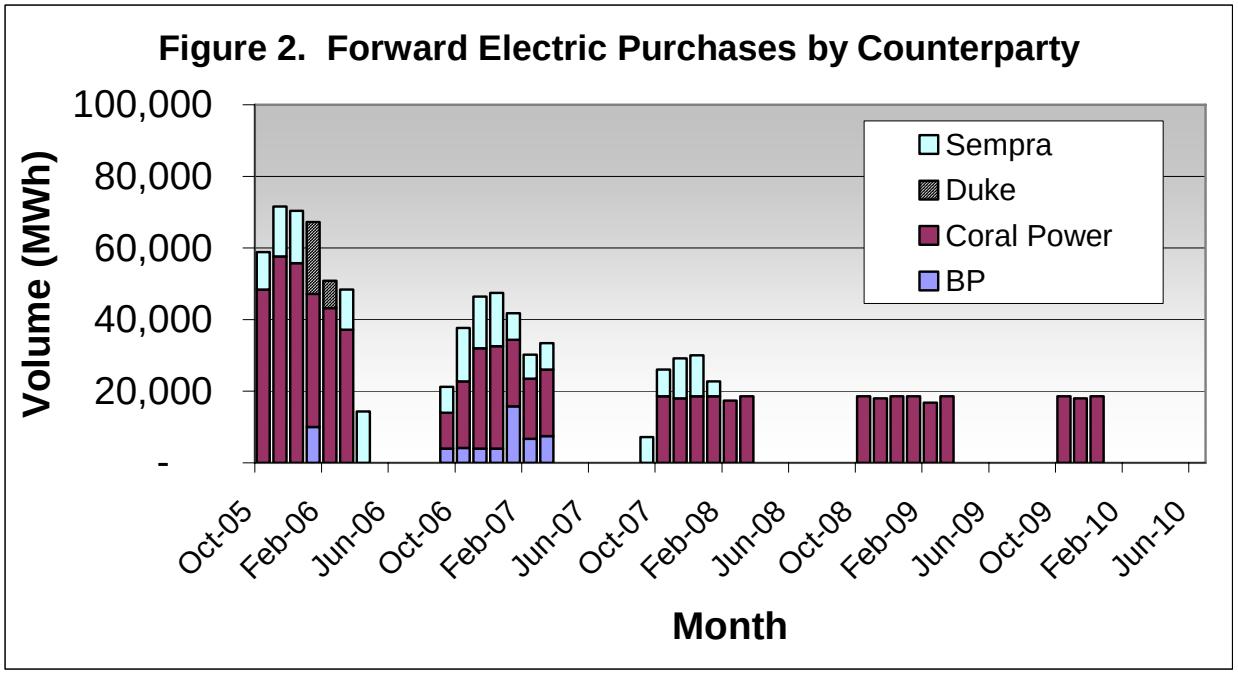
Electricity. As of September 30, 2005 the electric portfolio consisted of 81 open transactions (transactions for which commitments have been made but electricity remains to be delivered) through December 2009. Figure 1 illustrates the sources of electricity supplies by month for the next 36 months. The City currently has purchased supplies of electricity totaling 0.95 million MWh for delivery between October 1, 2005 and December 31, 2009. The average price for all of the fixed-price purchases was $47.48 per MWh, slightly down from $47.58 last quarter. The forward purchases have been transacted with four approved counterparties: Coral Energy, Duke Energy, Sempra Energy and British Petroleum. Note that in Figure 1, the Seattle City Light (SCL) volumes represent a "swap" whereby Palo Alto supplies power to Seattle City Light in the winter months and Seattle provides power to Palo Alto during the summer months. The distribution of purchases by month and by counterparty is presented in Figure 2.

Figure 1. Load Supply Balance for Electricity.



The Mark to Market (MTM) value represents the difference in price between the current market value of the contracted supply and the original contracted price. A positive MTM value indicates an increase in the value of the purchase, which would be realized only if the transaction was liquidated. While a positive MTM value represents an increase in value to the City, it also represents the City's credit exposure with the supplier. In other words, should a counterparty default on delivery of supply, the City would need to purchase replacement energy on the open market when prices could be higher. A negative MTM represents the supplier's credit exposure with the City.

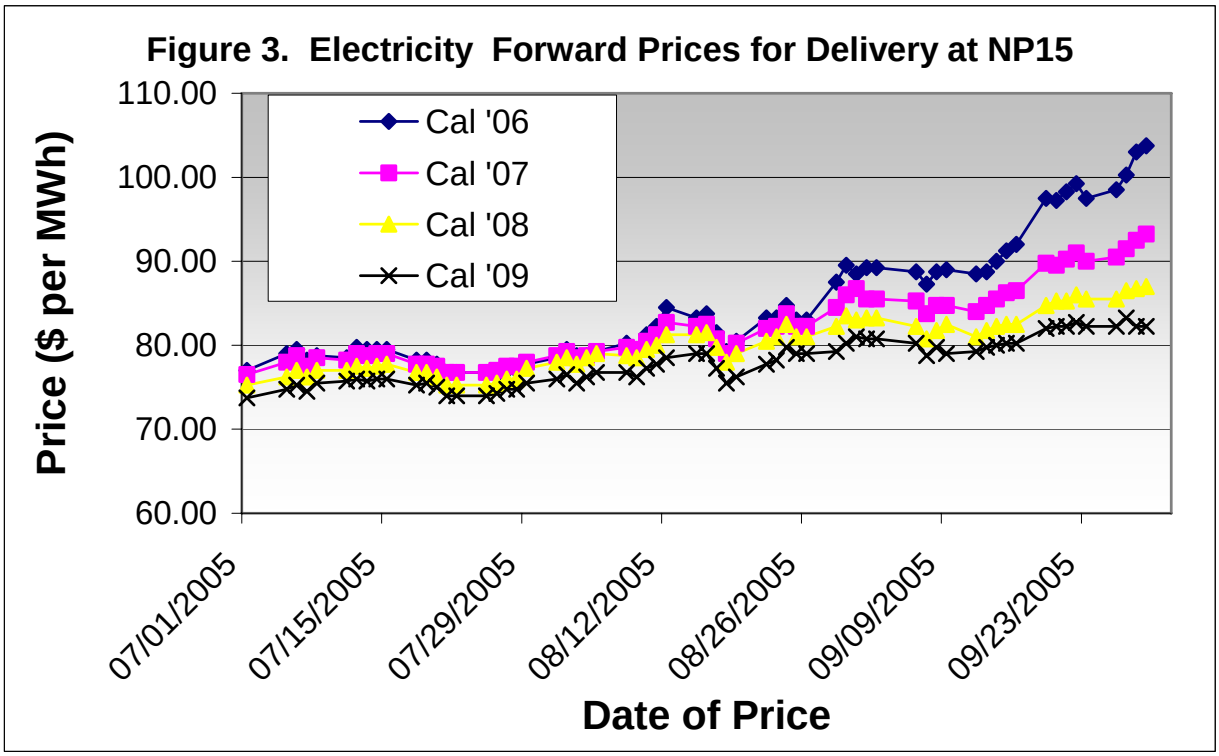
The MTM value is based on the current forward prices, that is the prices at the end of the quarter for deliveries in the future. Prices during the quarter increased dramatically, driven by infrastructure impacts of Hurricane Katrina which drove up energy prices in all sectors. During the quarter, prices for deliveries in Calendar Year (CY) 2006, increased from $77 to $103 per MWh. Prices increased by $17.00 for CY 2007, by $11.72 for CY 2008 and by $9.50 for CY 2009 (Figure 3). Because of the predominance of near term transactions in the City's portfolio, the total MTM value of the City's forward transactions more than doubled during the quarter from $19.6 million to $41.6 million. Figure 4 presents the MTM positions for each supplier by month.



Hydro Power. Based on forecasts provided by Western and the Calaveras Project and forward market projections, staff has calculated values for CPAU's hydro contracts. It should be noted that for both the Western and Calaveras, values are based on the expected volumes of delivery for the next 12 months. These values will change as actual volumes will differ from those predicted at this moment in time. At present, the value for Western through September 30, 2006

is $38.3 million, up from $19.5 million last quarter. For Calaveras, the 12-month value is $15.3 million, doubled from the previous quarter.

Seasonal Exchange Contracts. The sole seasonal exchange transaction in which Palo Alto is engaged involves Seattle City Light. Under this contract, which was signed in 1992, Palo Alto receives 9 MW from November through March, and sends 10 MW from June through October. The 12-month MTM value of this contract is approximately minus $106,000.



Note: NP15 refers to North Path 15 which serves as the key delivery and market point for Northern California. As such it represents an aggregated price for the region.

Wind Power. As noted in the previous report, the City recently signed a 23.5-year contract with Pacificorp Power Marketing (PPM) for supplies of wind energy. Wind power has different characteristics from a normal power purchase because it is not volumetrically firm. The amount Palo Alto receives directly relates to how strongly the wind blows. Based on historic meteorological conditions, Palo Alto expects to receive approximately 58,000 MWh per year.

Using the expected monthly volume averages for on-peak and off-peak, the MTM value of the contract is $1.87 million over the next 12 months, a 209% increase over last quarter. This MTM value, however, does not include the value of the Renewable Energy Credits associated with the production of the power. These credits have a variable value of between $2 and $12, but currently their market price is roughly $2.00 for 1 MWh blocks. The additional value of the credits puts the total MTM value of the contract at an estimated at $1.98 million for the next 12 months.

Natural Gas. As of September 30, 2005 the gas portfolio consisted of 201 open transactions (transactions for which commitments have been made but gas remains to be delivered) through July 2008. The City currently has purchased supplies of gas totaling 5.6 million MMBtu for delivery between October 1, 2005 and December 31, 2009. The average price for all of the fixed-price purchases was $6.21 per MMBtu, significantly up from $5.46 last quarter. The forward purchases have been transacted with five approved counterparties: Coral Energy, Duke Energy, Sempra Energy, ConocoPhillips and British Petroleum.

Figure 4. Electric Forward Mark to Market

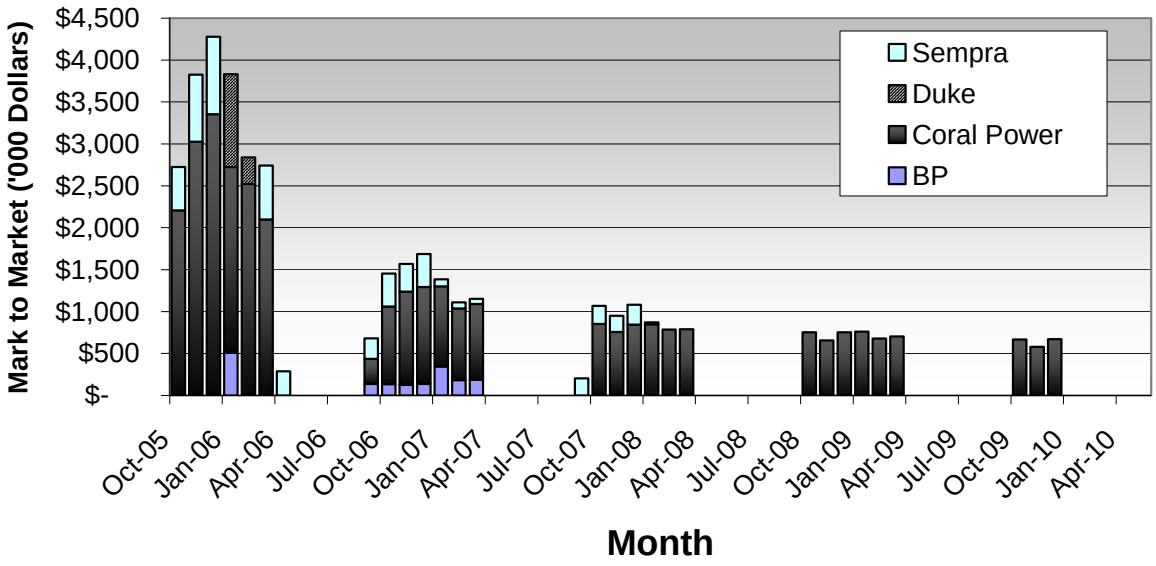
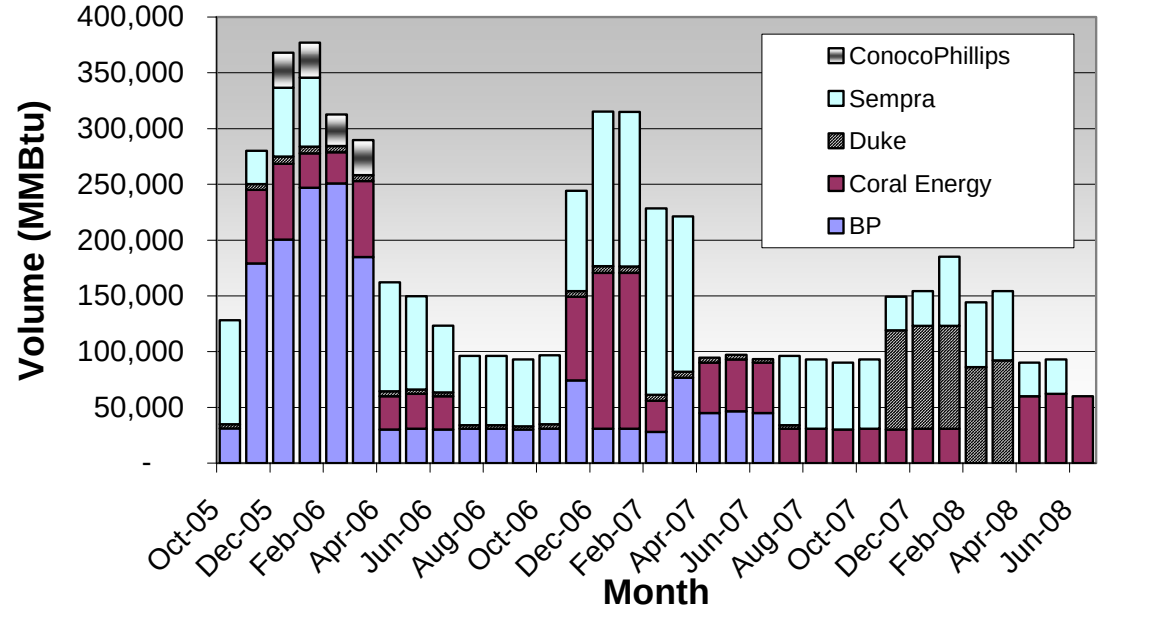
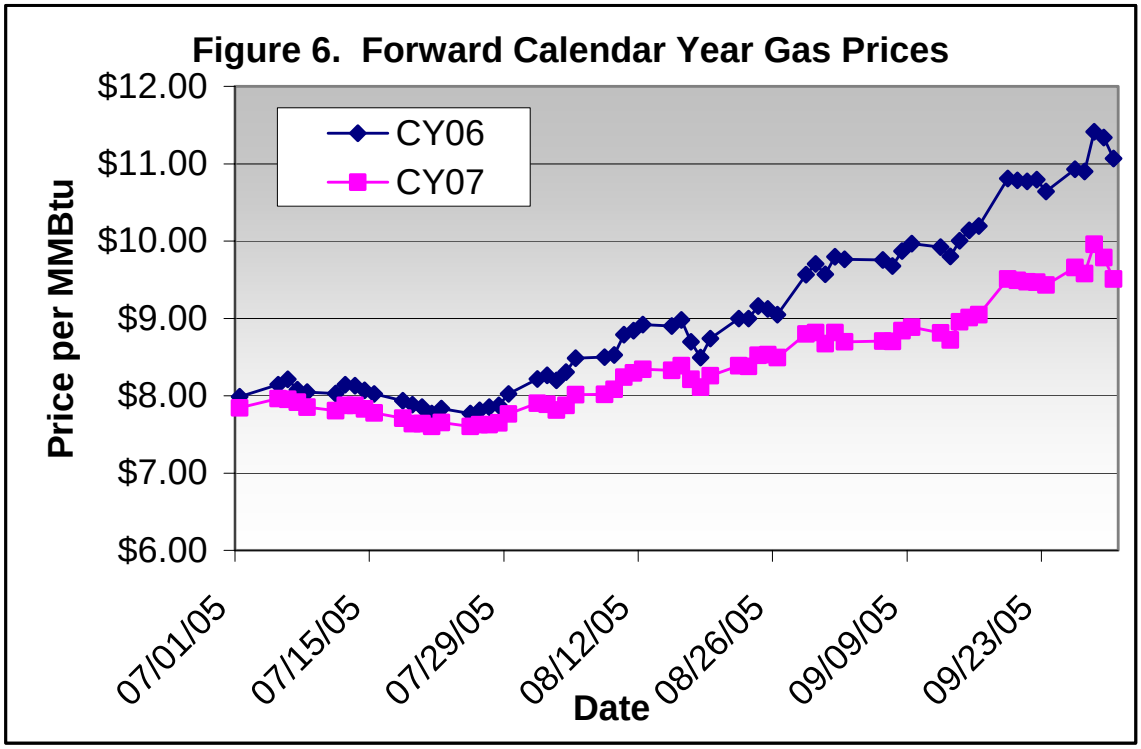


Figure 5. Forward Gas Purchase Volumes by Counterparty





Forward prices for gas increased by 63% over the quarter for delivery in Calendar Year 2006 (CY 06) delivery, and 20% for delivery in Calendar Year 2007 (Figure 6). The current MTM value of these transactions is $ 24.0 million, an increase of 144% from last quarter. The MTM value by month and by counterparty is presented in Figure 7.

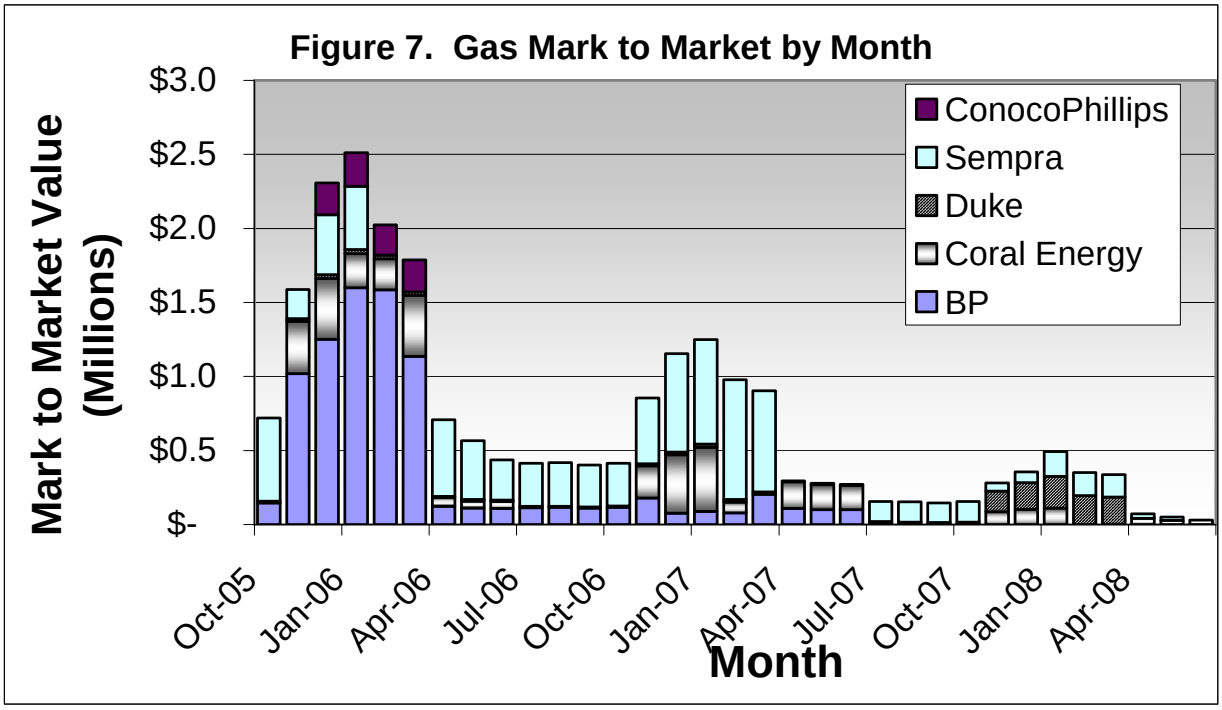
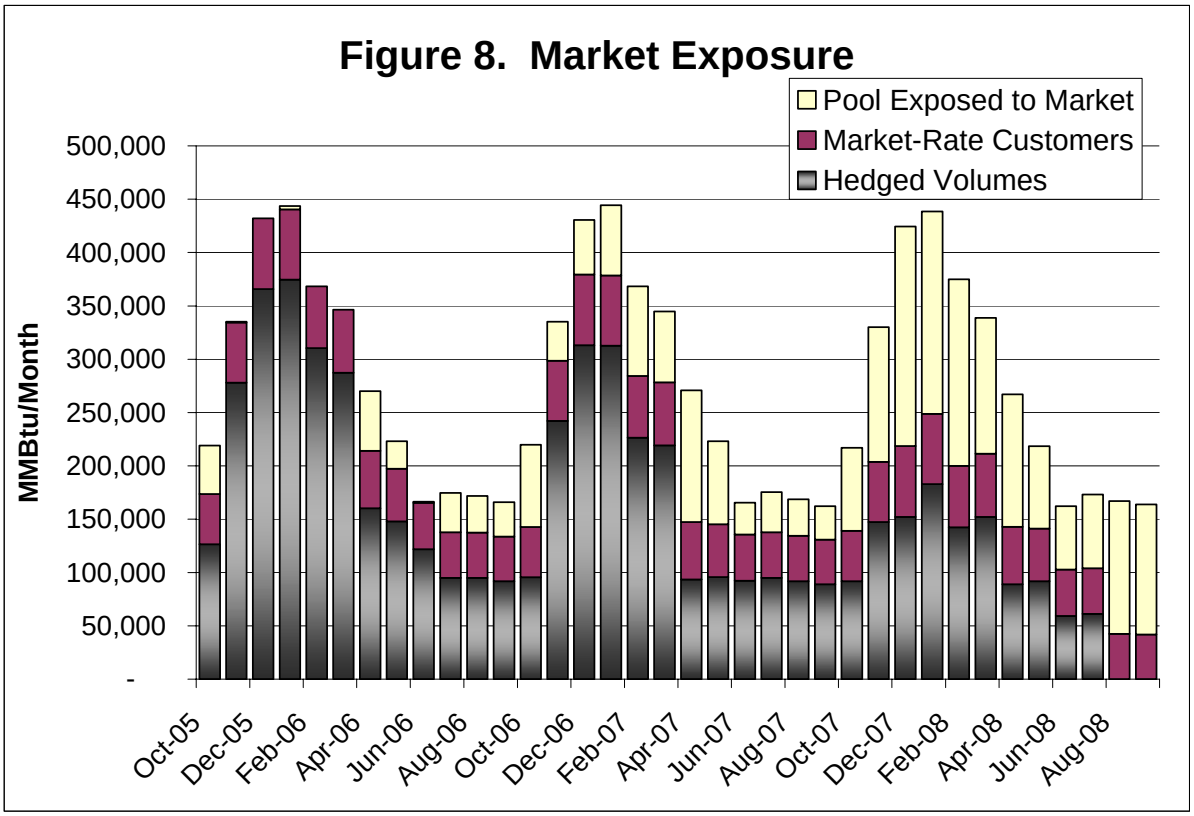
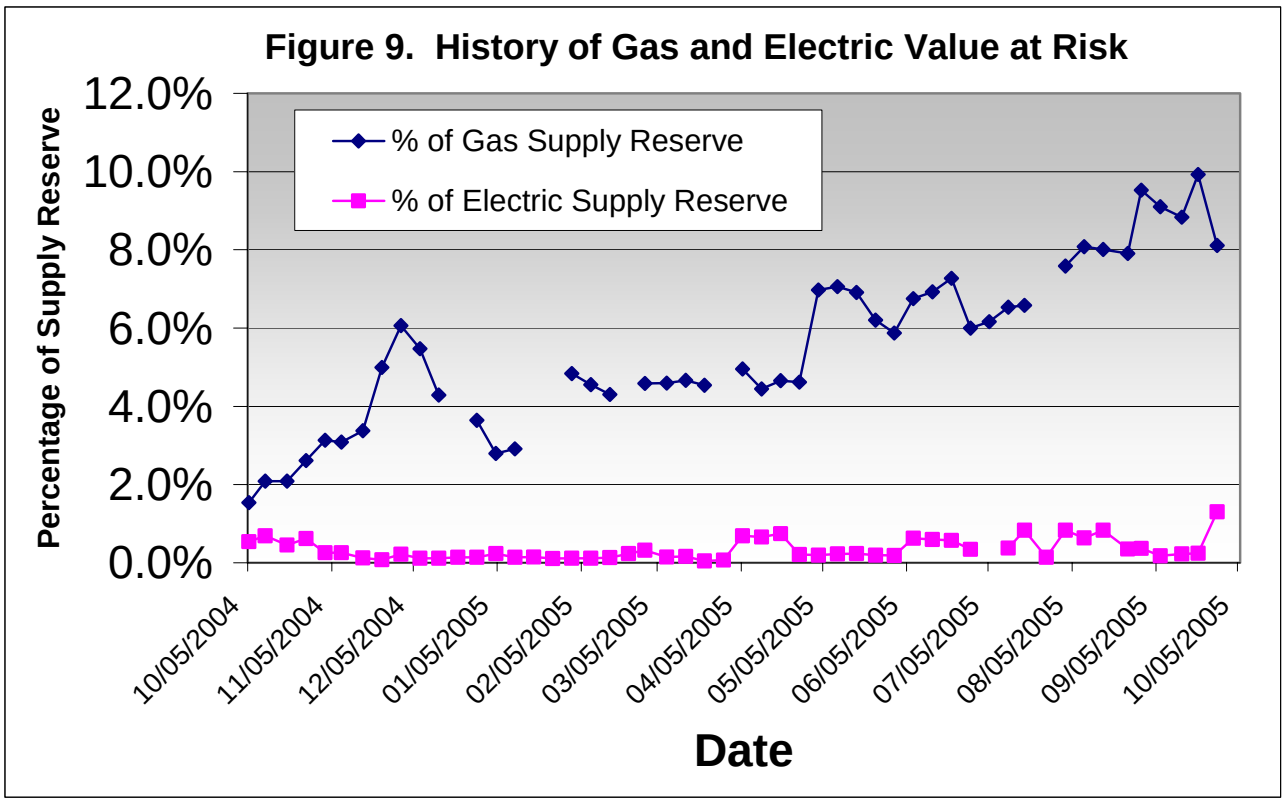


Figure 8 below presents the pool purchases made for each month over the next three years compared to estimated pool load. It illustrates the gas laddering purchasing strategy in relation to the total estimated load, showing the amount of volumes purchased (hedged volumes), the volume to be used by market rate customers, and the amount of pool to be purchased on the short-term market (pool exposed to market). Under the laddering strategy, CPAU purchases up to 100% of forecasted load for the upcoming 18 months, up to 75% of load for 19 to 27 months out, and up to 50% of load for 28 to 36 months out. As a result, the amount of pool exposure to the market is low in the near term, but increases further out in the future.



Value at Risk

The "riskiness" of the energy portfolio is measured through the "value at risk" (or VaR). The VaR measures the risk that adverse market conditions could force CPAU to use reserves to cover costs on future purchases over what is reflected in current rates. Specifically, VaR measures how much projected 12-month net revenue could change in one week due to a potential market change. Staff use the VaR as one of the key measures of risk to CPAU.



In compliance with the Risk Management Guidelines, the Utilities staff and the Energy Risk Manager monitor the VaR and ensure that its value remains below 10% of the projected end of year supply Rate Stabilization Reserve (RSR) levels for both electricity and gas. Currently, the VaR for the electricity portfolio is 0.13% of the RSR, a reduction from 0.35% in last quarter. During the quarter, the VaR climbed to 9.8%, before settling at an end-of-quarter figure of 8.0% of the RSR. The comparable figure from the previous quarter was 5.9%. The historic levels of the VaR values for electricity and gas are presented in Figure 9. Please note that in Figure 9, gaps in the graph indicate missing data.

The VaR increase is a direct result of much higher forward prices associated with Hurricane Katrina. The 10% VaR limit set by the Risk Manager in conjunction with the Risk Oversight Committee represents a benchmark to monitor the potential risk to which the City is exposed as a result of possible variability in the cost of supplies not yet purchased. In some instances, the exceedance of the 10% benchmark would indicate the need for the City to purchase additional forward supplies. However, at the present time, the risk representated by the VaR number is solely the result of the increases in energy prices. At this current moment, when prices are at or near historic highs, staff does not recommend additional purchases in order to reduce VaR levels. Rather, staff will continue to monitor VaR levels and make recommendations to limit risk exposure when appropriate.

Credit Risk

Staff has enhanced the City's credit oversight policies and procedures. As part of this process, staff will regularly report on major credit rating agency's (S&P and Moody's) scores, and, in addition, the "estimated default frequency" (EDF) using the Moody's KMV CreditEdge© system. The EDF is an estimated probability that a counterparty will default in the next 12 months. For example, a 0.2 EDF indicates a chance of 2 in 1000 that the firm will be in default in the time period. Thus a higher EDF represents a higher credit risk for the City. While the current risk management practices do not set a specific EDF upper limit, any counterparty with a value over 0.50 warrants careful and regular monitoring of its financial condition and outlook.

Electricity. CPAU's electric supplier counterparty credit exposure and the supplier credit ratings are presented below. CPAU's largest exposure, in excess of $32.7 million, is with Coral, a company rated A- by Standard and Poors. Coral is a wholly owed subsidiary of Royal Dutch Shell which is rated AAA, the highest rating given.

Table 1. Electricity Suppliers – Credit Exposure and Credit Ratings as of September 30, 2005.

Counter party	Credit Exposure	S&P Ranking	Previous Quarter Expected Default Frequency	Current Expected Default Frequency	Expected "Loss"[2]
BP	$1,763,232	AA+	**.02**	**.02**	$ 114
Coral[1]	$32,724,416	A-	**.05**	.05	$8,469
Duke	$1,425,604	BBB	**.17**	**.11**	$ 459
Sempra	$5,626,878	BBB+	**.17**	**.09**	$3,141
Total	$41,540,130				$12,183

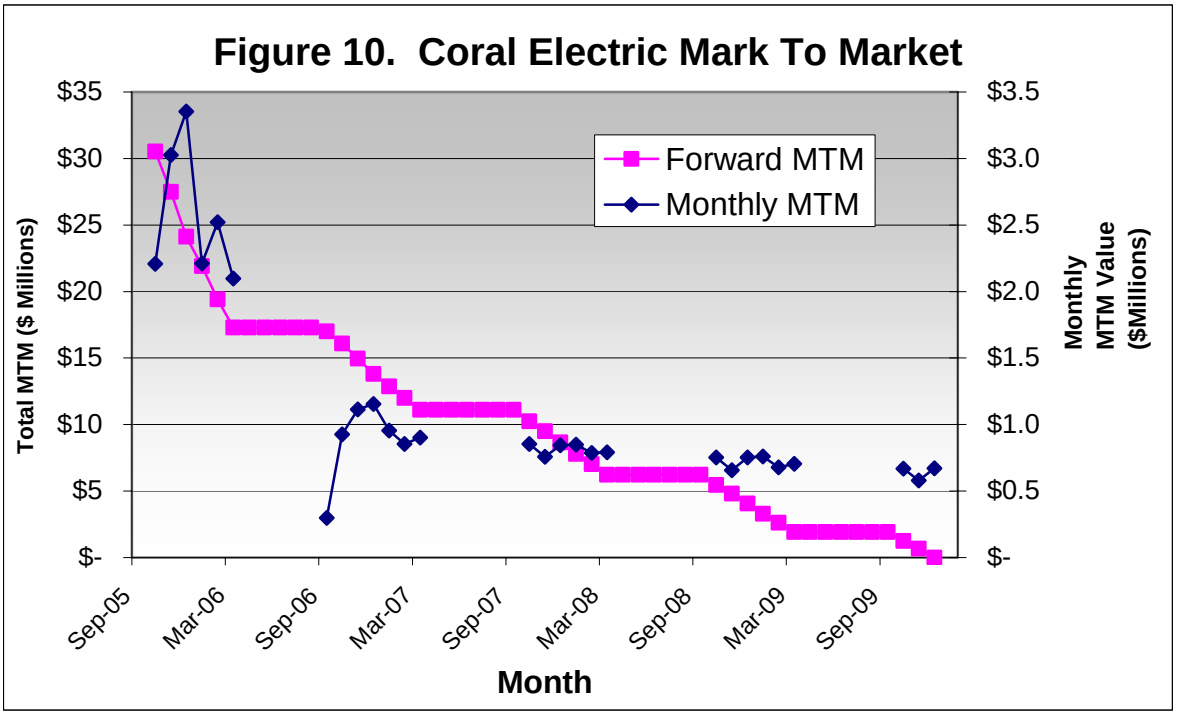
1 Coral was previously owned by Shell (70%) and Intergen (30%). Recently Coral became wholly owned by Shell PLC.

2 Expected loss represents the product of the default rate in the next 12 months and credit exposure. As such it provides an estimate of the 12-month average risk being carried by CPAU as a result of its forward contracts. Default frequencies are independently calculated, and cross-default probabilities (that change the one firm's default will increase the chances of another firm defaulting) are not included.

3 This estimate is based on the credit ratings, and not the KMV model results.

The City's current very large exposure to Coral is a reflection of the 5 year contract for electricity supplies at a cost of $37 per MWh. The current appreciation in prices due to weather factors renders this contract very valuable, and therefore a credit risk. This risk is being mitigated by daily monitoring of the City's exposure and regular and rigorous monitoring of Coral's financial and credit health. Finally, the short term run up in prices makes the next 6

months of the contract very valuable, with a MTM value in excess of $15 million. As can be seen in Figure 10, the MTM value of the contract declines rapidly as the energy is delivered .



Renewable Electricity . Palo Alto's contracts for renewable "green" energy include both wind contracts with Pacificorp Power Marketing (PPM), discussed above, as well as contracts to convert landfill gas to electricity with Ameresco, Inc. Neither PPM (owned by Scottish Power) nor Ameresco are publicly traded and therefore KMV Credit Edge does not include them in its default reporting. The Risk Manager has used financial information provided confidentially by each of the two counterparties to estimate an Expected Default Frequency, which is statistically comparable to the EDF's reported for the other counterparties. The Credit Exposure and EDF ratings for these counterparties are presented below.

Table 2. Green Energy Credit Exposure and Credit Ratings as of September 30, 2005.

Counterparty	Credit Exposure	Previous Quarter Calculated Expected Default Frequency	Current Calculated Expected Default Frequency	Expected "Loss"
Ameresco, Inc.	$ 0	N/A	0.85	$0
Pacificorp Power Marketing	$1,978,064	0.50	0.58	$11,472

Natural Gas. As the Table 3 shows, the City has exposure to five counterparties totaling $24.0 million over the next 36 months, an increase of over 250% since the last quarter. As with electricity, this large jump in the market exposure is the result of the rapid rise in the forward

energy prices. The highest exposure with a single supplier is $8.7 million with Sempra, a BBB+ company, with the second highest exposure being with AA+ rated BP at $8.6 million. The remainder of the exposure is distributed between two other counterparties.

The Table 3 below calculates, the loss which the City would suffer should one of gas counterparties defaults. This loss is calculated as the product of Estimated Default Frequency and the MTM value.

Table 3. Credit Exposure and Default Ratings of Natural Gas Suppliers
Gas Supplier Credit Exposure and Credit Rating as of September 30, 2005.

Counter party	Credit Exposure	S&P Ranking	Previous Expected Default Frequency	Current Expected Default Frequency	Expected Loss[2]
BP	$8,967,410	AA+	.02	.02	$1,793
ConocoPhillips	$ 909,702	A-	.02	.02	$181
Coral[1]	$ 4,085,131	A-	. 05[3]	.05[3]	$2,042
Duke	$ 1,307,039	BBB	.17	.11	$1,438
Sempra	$8,730,258	BBB+	.17	.09	$7,857
Total	$23,999,540				$13,311

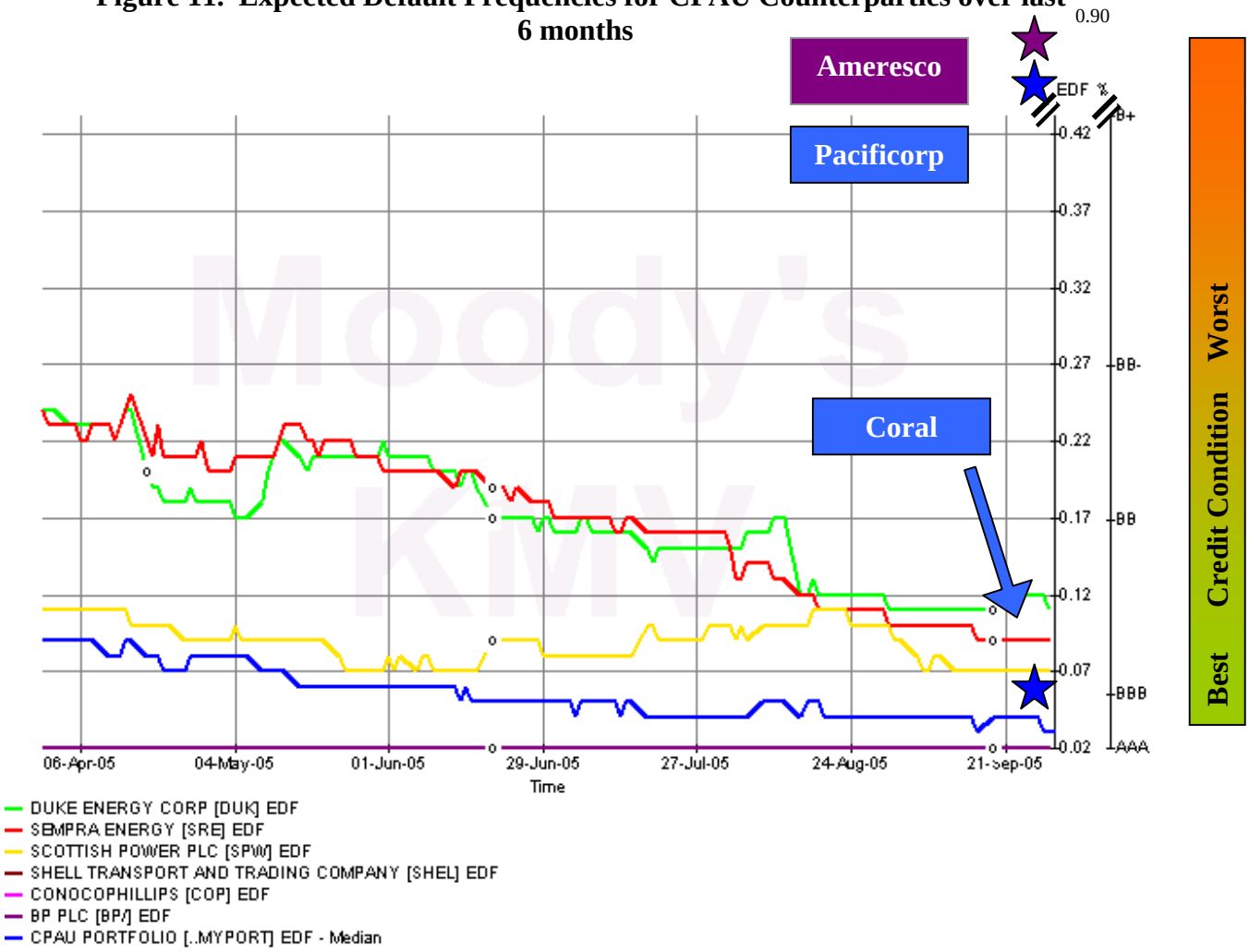
1 *Recently Coral became wholly owned by Shell PLC.*
2 *Expected loss represents the product of the default rate in the next 12 months and credit exposure. As such it provides an estimate of the 12-month average risk being carried by CPAU as a result of its forward contracts. Default frequencies are independently calculated, and cross-default probabilities(that change the one firm's default will increase the chances of another firm defaulting) are not included.*
3 *This estimate is based on the credit ratings, and not the KMV model results.*

Credit Quality of Suppliers. Overall, the City's suppliers have continued to improve their credit quality. Figure 10 shows how the expected default frequency of CPAU's current suppliers has declined (i.e. improved credit) over the past three years. As mentioned previously, Pacificorp Power Marketers is privately held and therefore an EDF is not issued by Moody's KMV. The firm's sole owner, Scottish Power, is used as a surrogate EDF. Similarly, Coral is the wholly owned subsidiary of Shell. The Coral EDF is calculated manually on a quarterly basis based on

confidential financial information provided by the company. The estimate is also adjusted after consultantion with credit analysts at Standard and Poors and Moody's Investor Services.

The staff-calculated EDF point estimates for Pacificorp Power Marketers, Coral and Ameresco are included on the Figure 11.

Figure 11. Expected Default Frequencies for CPAU Counterparties over last 6 months



Note: The Pacificorp, Coral and Ameresco EDF values shown above are point estimates calculated by staff from confidential financial information. As such, tracking is done on a quarterly basis and is not continuous.

PREPARED BY: _____

KARL VAN ORSDOL
Energy Risk Manager

DEPARTMENT HEAD APPROVAL: _____

CARL YEATS
Director, Administrative Services

CITY MANAGER APPROVAL: _____

EMILY HARRISON
Assistant City Manager

ATTACHMENTS

A) Consolidated Mark to Market Report of All Open Gas Transactions as of September 30, 2005
B) Consolidated Mark to Market Report of All Open Electric Transactions as of September 30, 2005

Appendix A
Gas Transaction Report
September 30, 2005

Counterparty	Delivery Point	Delivery Period	Deal Type	MMBtu per day	Price	Days In Month	End Use	Total Volume (MMBtu)	Total Cost	Market Value per MMBtu	Total Mark to Market
BP	Malin	Oct-05	Purchase	1,008	$ 5.63	31	Pool	31,248	$ 175,863.74	$ 10.07	$ 138,679
Duke	CG	Oct-05	Purchase	-	$ -	31	G11	-	$ -	$ 10.58	-
Duke	Malin	Oct-05	Purchase	120	$ 7.18	31	G11	3,720	$ 26,709.60	$ 10.07	$ 10,736
Sempra	Malin	Oct-05	Purchase	1,000	$ 3.92	31	Pool	31,000	$ 121,520.00	$ 10.07	$ 190,526
Sempra	Malin	Oct-05	Purchase	1,000	$ 4.29	31	Pool	31,000	$ 132,990.00	$ 10.07	$ 179,056
Sempra	Malin	Oct-05	Purchase	1,000	$ 4.68	31	Pool	31,000	$ 145,079.99	$ 10.07	$ 166,966
BP	CG	Nov-05	Purchase	1,000	$ 7.05	30	Pool	30,000	$ 211,649.99	$ 11.84	$ 143,400
BP	CG	Nov-05	Purchase	1,000	$ 6.55	30	Pool	30,000	$ 196,500.01	$ 11.84	$ 158,550
BP	Malin	Nov-05	Purchase	1,008	$ 5.63	30	Pool	30,240	$ 170,190.71	$ 11.54	$ 178,628
BP	Malin	Nov-05	Purchase	2,500	$ 4.73	30	Pool	75,000	$ 354,750.00	$ 11.54	$ 510,375
BP	Malin	Nov-05	Purchase	462	$ 6.36	30	Pool	13,860	$ 88,080.30	$ 11.54	$ 71,795
Coral Energy	CG	Nov-05	Purchase	1,200	$ 7.09	30	Pool	36,000	$ 255,240.01	$ 11.84	$ 170,820
Coral Energy	Malin	Nov-05	Purchase	1,000	$ 4.98	30	Pool	30,000	$ 149,400.00	$ 11.54	$ 196,650
Duke	CG	Nov-05	Purchase	170	$ 7.98	30	G11	5,100	$ 40,698.00	$ 11.84	$ 19,660
Duke	Malin	Nov-05	Purchase	-	$ -	30	G11	-	$ -	$ 11.54	$ -
Sempra	Malin	Nov-05	Purchase	1,000	$ 4.68	30	Pool	30,000	$ 140,399.99	$ 11.54	$ 205,650
BP	CG	Dec-05	Purchase	1,000	$ 7.05	31	Pool	31,000	$ 218,704.99	$ 12.67	$ 173,988
BP	CG	Dec-05	Purchase	1,000	$ 6.55	31	Pool	31,000	$ 203,050.01	$ 12.67	$ 189,642
BP	CG	Dec-05	Purchase	1,500	$ 6.54	31	Pool	46,500	$ 304,110.00	$ 12.67	$ 284,929
BP	Malin	Dec-05	Purchase	2,500	$ 4.73	31	Pool	77,500	$ 366,575.00	$ 12.37	$ 591,712
BP	Malin	Dec-05	Purchase	462	$ 6.36	31	Pool	14,322	$ 91,016.31	$ 12.37	$ 86,075
ConocoPhillips	Malin	Dec-05	Purchase	1,008	$ 5.15	31	Pool	31,248	$ 160,927.20	$ 12.37	$ 225,454
Coral Energy	CG	Dec-05	Purchase	1,200	$ 7.09	31	Pool	37,200	$ 263,748.01	$ 12.67	$ 207,483
Coral Energy	Malin	Dec-05	Purchase	1,000	$ 4.98	31	Pool	31,000	$ 154,380.00	$ 12.37	$ 228,935
Duke	CG	Dec-05	Purchase	200	$ 7.98	31	G11	6,200	$ 49,476.00	$ 12.67	$ 29,062
Duke	Malin	Dec-05	Purchase	-	$ -	31	G11	-	$ -	$ 12.37	$ -
Sempra	CG	Dec-05	Purchase	1,000	$ 6.56	31	Pool	31,000	$ 203,344.51	$ 12.67	$ 189,348
Sempra	Malin	Dec-05	Purchase	1,000	$ 4.68	31	Pool	31,000	$ 145,079.99	$ 12.37	$ 238,235
BP	CG	Jan-06	Purchase	1,500	$ 6.77	31	Pool	46,500	$ 314,805.00	$ 13.13	$ 295,624
BP	CG	Jan-06	Purchase	1,000	$ 7.05	31	Pool	31,000	$ 218,704.99	$ 13.13	$ 188,248
BP	CG	Jan-06	Purchase	1,000	$ 6.55	31	Pool	31,000	$ 203,050.01	$ 13.13	$ 203,902
BP	CG	Jan-06	Purchase	1,500	$ 6.54	31	Pool	46,500	$ 304,110.00	$ 13.13	$ 306,319
BP	Malin	Jan-06	Purchase	2,500	$ 4.73	31	Pool	77,500	$ 366,575.00	$ 12.83	$ 627,362
BP	Malin	Jan-06	Purchase	462	$ 6.36	31	Pool	14,322	$ 91,016.31	$ 12.83	$ 92,663
ConocoPhillips	Malin	Jan-06	Purchase	1,008	$ 5.15	31	Pool	31,248	$ 160,927.20	$ 12.83	$ 239,828

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Counterparty	Delivery Point	Delivery Period	Deal Type	MMBtu per day	Price	Days In Month	End Use	Total Volume (MMBtu)	Total Cost	Market Value per MMBtu	Total Mark to Market
Coral Energy	CG	Jan-06	Purchase	-	$ -	31	Pool	-	$ -	$ 13.13	$ -
Coral Energy	Malin	Jan-06	Purchase	1,000	$ 4.98	31	Pool	31,000	$ 154,380.00	$ 12.83	$ 243,195
Duke	CG	Jan-06	Purchase	190	$ 7.98	31	G11	5,890	$ 47,002.20	$ 13.13	$ 30,319
Duke	Malin	Jan-06	Purchase	-	$ -	31	G11	-	$ -	$ 12.83	$ -
Sempra	CG	Jan-06	Purchase	1,000	$ 6.56	31	Pool	31,000	$ 203,344.51	$ 13.13	$ 203,608
Sempra	Malin	Jan-06	Purchase	1,000	$ 4.68	31	Pool	31,000	$ 145,079.99	$ 12.83	$ 252,495
BP	CG	Feb-06	Purchase	1,500	$ 6.77	28	Pool	42,000	$ 284,340.00	$ 13.15	$ 267,855
BP	CG	Feb-06	Purchase	2,500	$ 7.54	28	Pool	70,000	$ 527,800.00	$ 13.15	$ 392,525
BP	CG	Feb-06	Purchase	1,000	$ 7.05	28	Pool	28,000	$ 197,540.00	$ 13.15	$ 170,590
BP	CG	Feb-06	Purchase	-	$ -	28	Pool	-	$ -	$ 13.15	$ -
BP	Malin	Feb-06	Purchase	1,000	$ 5.43	28	Pool	28,000	$ 151,900.01	$ 12.85	$ 207,900
BP	Malin	Feb-06	Purchase	2,500	$ 4.73	28	Pool	70,000	$ 331,100.00	$ 12.85	$ 568,400
BP	Malin	Feb-06	Purchase	462	$ 6.36	28	Pool	12,936	$ 82,208.28	$ 12.85	$ 84,019
ConocoPhillips	Malin	Feb-06	Purchase	1,008	$ 5.15	28	Pool	28,224	$ 145,353.60	$ 12.85	$ 217,325
Coral Energy	CG	Feb-06	Purchase	-	$ -	28	Pool	-	$ -	$ 13.15	$ -
Coral Energy	Malin	Feb-06	Purchase	1,000	$ 4.98	28	Pool	28,000	$ 139,440.00	$ 12.85	$ 220,360
Duke	CG	Feb-06	Purchase	190	$ 7.98	28	G11	5,320	$ 42,453.60	$ 13.15	$ 27,491
Duke	Malin	Feb-06	Purchase	-	$ -	28	G11	-	$ -	$ 12.85	$ -
BP	CG	Mar-06	Purchase	1,000	$ 7.05	31	Pool	31,000	$ 218,704.99	$ 12.72	$ 175,538
BP	CG	Mar-06	Purchase	1,000	$ 6.55	31	Pool	31,000	$ 203,050.01	$ 12.72	$ 191,192
BP	Malin	Mar-06	Purchase	1,000	$ 7.32	31	Pool	31,000	$ 226,920.01	$ 12.42	$ 158,022
BP	Malin	Mar-06	Purchase	2,500	$ 4.73	31	Pool	77,500	$ 366,575.00	$ 12.42	$ 595,781
BP	Malin	Mar-06	Purchase	462	$ 6.36	31	Pool	14,322	$ 91,016.31	$ 12.42	$ 86,827
ConocoPhillips	Malin	Mar-06	Purchase	1,008	$ 5.15	31	Pool	31,248	$ 160,927.20	$ 12.42	$ 227,095
Coral Energy	CG	Mar-06	Purchase	1,200	$ 7.09	31	Pool	37,200	$ 263,748.01	$ 12.72	$ 209,343
Coral Energy	Malin	Mar-06	Purchase	1,000	$ 4.98	31	Pool	31,000	$ 154,380.00	$ 12.42	$ 230,562
Duke	CG	Mar-06	Purchase	170	$ 7.98	31	G11	5,270	$ 42,054.60	$ 12.72	$ 24,967
Duke	Malin	Mar-06	Purchase	-	$ -	31	G11	-	$ -	$ 12.42	$ -
BP	Malin	Apr-06	Purchase	1,000	$ 5.78	30	Pool	30,000	$ 173,400.01	$ 9.96	$ 125,250
Coral Energy	Malin	Apr-06	Purchase	1,000	$ 7.89	30	Pool	30,000	$ 236,850.00	$ 9.96	$ 61,800
Duke	CG	Apr-06	Purchase	150	$ 7.98	30	G11	4,500	$ 35,910.00	$ 10.23	$ 10,125
Duke	Malin	Apr-06	Purchase	-	$ -	30	G11	-	$ -	$ 9.96	$ -
Sempra	Malin	Apr-06	Purchase	750	$ 4.66	30	Pool	22,500	$ 104,850.00	$ 9.96	$ 119,138
Sempra	Malin	Apr-06	Purchase	1,000	$ 4.27	30	Pool	30,000	$ 128,100.00	$ 9.96	$ 170,550
Sempra	Malin	Apr-06	Purchase	1,500	$ 4.65	30	Pool	45,000	$ 209,250.00	$ 9.96	$ 238,725

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Counterparty	Delivery Point	Delivery Period	Deal Type	MMBtu per day	Price	Days In Month	End Use	Total Volume (MMBtu)	Total Cost	Market Value per MMBtu	Total Mark to Market
BP	Malin	May-06	Purchase	1,000	$ 5.78	31	Pool	31,000	$ 179,180.01	$ 9.45	$ 113,615
Coral Energy	Malin	May-06	Purchase	1,000	$ 7.89	31	Pool	31,000	$ 244,745.00	$ 9.45	$ 48,050
Duke	CG	May-06	Purchase	-	$ -	31	G11	-	$ -	$ 9.72	$ -
Duke	Malin	May-06	Purchase	130	$ 6.74	31	G11	4,030	$ 27,162.20	$ 9.45	$ 10,901
Sempra	Malin	May-06	Purchase	1,200	$ 4.66	31	Pool	37,200	$ 173,351.99	$ 9.45	$ 178,002
Sempra	Malin	May-06	Purchase	1,500	$ 4.65	31	Pool	46,500	$ 216,225.00	$ 9.45	$ 222,967
BP	Malin	Jun-06	Purchase	1,000	$ 5.78	30	Pool	30,000	$ 173,400.01	$ 9.47	$ 110,760
Coral Energy	Malin	Jun-06	Purchase	1,000	$ 7.89	30	Pool	30,000	$ 236,850.00	$ 9.47	$ 47,310
Duke	CG	Jun-06	Purchase	-	$ -	30	G11	-	$ -	$ 9.75	$ -
Duke	Malin	Jun-06	Purchase	110	$ 6.74	30	G11	3,300	$ 22,242.00	$ 9.47	$ 9,016
Sempra	Malin	Jun-06	Purchase	1,000	$ 4.66	30	Pool	30,000	$ 139,800.00	$ 9.47	$ 144,360
Sempra	Malin	Jun-06	Purchase	1,000	$ 5.06	30	Pool	30,000	$ 151,785.01	$ 9.47	$ 132,375
BP	Malin	Jul-06	Purchase	1,000	$ 5.78	31	Pool	31,000	$ 179,180.01	$ 9.52	$ 115,785
Duke	CG	Jul-06	Purchase	-	$ -	31	G11	-	$ -	$ 10.25	$ -
Duke	Malin	Jul-06	Purchase	100	$ 6.74	31	G11	3,100	$ 20,894.00	$ 9.52	$ 8,603
Sempra	Malin	Jul-06	Purchase	1,000	$ 5.06	31	Pool	31,000	$ 156,844.51	$ 9.52	$ 138,120
Sempra	Malin	Jul-06	Purchase	1,000	$ 4.48	31	Pool	31,000	$ 138,880.00	$ 9.52	$ 156,085
BP	Malin	Aug-06	Purchase	1,000	$ 5.78	31	Pool	31,000	$ 179,180.01	$ 9.56	$ 117,242
Duke	CG	Aug-06	Purchase	-	$ -	31	G11	-	$ -	$ 10.30	$ -
Duke	Malin	Aug-06	Purchase	100	$ 6.74	31	G11	3,100	$ 20,894.00	$ 9.56	$ 8,748
Sempra	Malin	Aug-06	Purchase	1,000	$ 5.06	31	Pool	31,000	$ 156,844.51	$ 9.56	$ 139,577
Sempra	Malin	Aug-06	Purchase	1,000	$ 4.48	31	Pool	31,000	$ 138,880.00	$ 9.56	$ 157,542
BP	Malin	Sep-06	Purchase	1,000	$ 5.78	30	Pool	30,000	$ 173,400.01	$ 9.54	$ 112,860
Duke	CG	Sep-06	Purchase	-	$ -	30	G11	-	$ -	$ 10.27	$ -
Duke	Malin	Sep-06	Purchase	100	$ 6.74	30	G11	3,000	$ 20,220.00	$ 9.54	$ 8,406
Sempra	Malin	Sep-06	Purchase	1,000	$ 5.06	30	Pool	30,000	$ 151,785.01	$ 9.54	$ 134,475
Sempra	Malin	Sep-06	Purchase	1,000	$ 4.48	30	Pool	30,000	$ 134,400.00	$ 9.54	$ 151,860
BP	Malin	Oct-06	Purchase	1,000	$ 5.78	31	Pool	31,000	$ 179,180.01	$ 9.57	$ 117,614
Duke	CG	Oct-06	Purchase	-	$ -	31	G11	-	$ -	$ 9.95	$ -
Duke	Malin	Oct-06	Purchase	120	$ 6.74	31	G11	3,720	$ 25,072.80	$ 9.57	$ 10,542
Sempra	Malin	Oct-06	Purchase	2,000	$ 4.89	31	Pool	62,000	$ 303,490.00	$ 9.57	$ 290,098
BP	CG	Nov-06	Purchase	1,000	$ 8.11	30	Pool	30,000	$ 243,299.99	$ 10.47	$ 70,920
BP	Malin	Nov-06	Purchase	1,470	$ 7.24	30	Pool	44,100	$ 319,283.99	$ 10.14	$ 127,846
Coral Energy	CG	Nov-06	Purchase	1,000	$ 8.25	30	Pool	30,000	$ 247,500.00	$ 10.47	$ 66,720
Coral Energy	Malin	Nov-06	Purchase	1,500	$ 6.34	30	Pool	45,000	$ 285,524.99	$ 10.14	$ 170,730

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Counterparty	Delivery Point	Delivery Period	Deal Type	MMBtu per day	Price	Days In Month	End Use	Total Volume (MMBtu)	Total Cost	Market Value per MMBtu	Total Mark to Market
Duke	CG	Nov-06	Purchase	170	$ 7.60	30	G11	5,100	$ 38,760.00	$ 10.47	$ 14,657
Duke	Malin	Nov-06	Purchase	-	$ -	30	G11	-	$ -	$ 10.14	$ -
Sempra	Malin	Nov-06	Purchase	2,000	$ 4.89	30	Pool	60,000	$ 293,700.00	$ 10.14	$ 314,640
Sempra	Malin	Nov-06	Purchase	1,000	$ 5.03	30	Pool	30,000	$ 150,900.01	$ 10.14	$ 153,270
BP	CG	Dec-06	Purchase	1,000	$ 8.11	31	Pool	31,000	$ 251,409.99	$ 10.90	$ 86,490
Coral Energy	CG	Dec-06	Purchase	1,000	$ 8.25	31	Pool	31,000	$ 255,750.00	$ 10.90	$ 82,150
Coral Energy	CG	Dec-06	Purchase	1,000	$ 8.04	31	Pool	31,000	$ 249,240.00	$ 10.90	$ 88,660
Coral Energy	CG	Dec-06	Purchase	1,000	$ 8.81	31	Pool	31,000	$ 273,110.01	$ 10.90	$ 64,790
Coral Energy	Malin	Dec-06	Purchase	1,500	$ 6.34	31	Pool	46,500	$ 295,042.49	$ 10.55	$ 195,719
Duke	CG	Dec-06	Purchase	200	$ 7.60	31	G11	6,200	$ 47,120.00	$ 10.90	$ 20,460
Duke	Malin	Dec-06	Purchase	-	$ -	31	G11	-	$ -	$ 10.55	$ -
Sempra	Malin	Dec-06	Purchase	2,000	$ 4.89	31	Pool	62,000	$ 303,490.00	$ 10.55	$ 350,858
Sempra	Malin	Dec-06	Purchase	1,000	$ 5.03	31	Pool	31,000	$ 155,930.01	$ 10.55	$ 171,244
Sempra	Malin	Dec-06	Purchase	1,470	$ 6.64	31	Pool	45,570	$ 302,584.79	$ 10.55	$ 178,361
BP	CG	Jan-07	Purchase	1,000	$ 8.11	31	Pool	31,000	$ 251,409.99	$ 11.19	$ 95,604
Coral Energy	CG	Jan-07	Purchase	1,000	$ 8.25	31	Pool	31,000	$ 255,750.00	$ 11.19	$ 91,264
Coral Energy	CG	Jan-07	Purchase	1,000	$ 8.04	31	Pool	31,000	$ 249,240.00	$ 11.19	$ 97,774
Coral Energy	CG	Jan-07	Purchase	1,000	$ 8.81	31	Pool	31,000	$ 273,110.01	$ 11.19	$ 73,904
Coral Energy	Malin	Jan-07	Purchase	1,500	$ 6.34	31	Pool	46,500	$ 295,042.49	$ 10.86	$ 209,901
Duke	CG	Jan-07	Purchase	190	$ 7.60	31	G11	5,890	$ 44,764.00	$ 11.19	$ 21,169
Duke	Malin	Jan-07	Purchase	-	$ -	31	G11	-	$ -	$ 10.86	$ -
Sempra	Malin	Jan-07	Purchase	2,000	$ 4.89	31	Pool	62,000	$ 303,490.00	$ 10.86	$ 369,768
Sempra	Malin	Jan-07	Purchase	1,000	$ 5.03	31	Pool	31,000	$ 155,930.01	$ 10.86	$ 180,699
Sempra	Malin	Jan-07	Purchase	1,470	$ 6.64	31	Pool	45,570	$ 302,584.79	$ 10.86	$ 192,260
BP	CG	Feb-07	Purchase	1,000	$ 8.11	28	Pool	28,000	$ 227,079.99	$ 11.14	$ 84,812
Coral Energy	CG	Feb-07	Purchase	1,000	$ 8.25	28	Pool	28,000	$ 231,000.00	$ 11.14	$ 80,892
Duke	CG	Feb-07	Purchase	190	$ 7.60	28	G11	5,320	$ 40,432.00	$ 11.14	$ 18,827
Duke	Malin	Feb-07	Purchase	-	$ -	28	G11	-	$ -	$ 10.80	$ -
Sempra	Malin	Feb-07	Purchase	1,500	$ 6.39	28	Pool	42,000	$ 268,170.01	$ 10.80	$ 185,598
Sempra	Malin	Feb-07	Purchase	2,000	$ 4.89	28	Pool	56,000	$ 274,120.00	$ 10.80	$ 330,904
Sempra	Malin	Feb-07	Purchase	1,000	$ 5.03	28	Pool	28,000	$ 140,840.01	$ 10.80	$ 161,672
Sempra	Malin	Feb-07	Purchase	1,470	$ 6.64	28	Pool	41,160	$ 273,302.39	$ 10.80	$ 171,390
BP	CG	Mar-07	Purchase	1,000	$ 8.11	31	Pool	31,000	$ 251,409.99	$ 10.88	$ 85,839
BP	Malin	Mar-07	Purchase	1,470	$ 7.57	31		45,570	$ 345,192.74	$ 10.54	$ 135,297
Duke	CG	Mar-07	Purchase	170	$ 7.60	31	G11	5,270	$ 40,052.00	$ 10.88	$ 17,280

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Duke	Malin	Mar-07	Purchase	-	$ -	31	G11	-	$ -	$ 10.54	$ -
Sempra	Malin	Mar-07	Purchase	1,500	$ 6.39	31	Pool	46,500	$ 296,902.51	$ 10.54	$ 193,393
Sempra	Malin	Mar-07	Purchase	2,000	$ 4.89	31	Pool	62,000	$ 303,490.00	$ 10.54	$ 350,238
Sempra	Malin	Mar-07	Purchase	1,000	$ 5.03	31	Pool	31,000	$ 155,930.01	$ 10.54	$ 170,934
BP	Malin	Apr-07	Purchase	1,500	$ 6.13	30	Pool	45,000	$ 275,850.01	$ 8.73	$ 117,180
Coral Energy	Malin	Apr-07	Purchase	1,500	$ 4.63	30	Pool	45,000	$ 208,350.01	$ 8.73	$ 184,680
Duke	CG	Apr-07	Purchase	150	$ 7.60	30	G11	4,500	$ 34,200.00	$ 9.15	$ 6,975
Duke	Malin	Apr-07	Purchase	-	$ -	30	G11	-	$ -	$ 8.73	$ -
BP	Malin	May-07	Purchase	1,500	$ 6.13	31	Pool	46,500	$ 285,045.01	$ 8.40	$ 105,741
Coral Energy	Malin	May-07	Purchase	1,500	$ 4.63	31	Pool	46,500	$ 215,295.01	$ 8.40	$ 175,491
Duke	CG	May-07	Purchase	-	$ -	31	G11	-	$ -	$ 8.82	$ -
Duke	Malin	May-07	Purchase	130	$ 6.23	31	G11	4,030	$ 25,106.90	$ 8.40	$ 8,761
BP	Malin	Jun-07	Purchase	1,500	$ 6.13	30	Pool	45,000	$ 275,850.01	$ 8.45	$ 104,355
Coral Energy	Malin	Jun-07	Purchase	1,500	$ 4.63	30	Pool	45,000	$ 208,350.01	$ 8.45	$ 171,855
Duke	CG	Jun-07	Purchase	-	$ -	30	G11	-	$ -	$ 8.87	$ -
Duke	Malin	Jun-07	Purchase	110	$ 6.23	30	G11	3,300	$ 20,559.00	$ 8.45	$ 7,323
Coral Energy	Malin	Jul-07	Purchase	1,000	$ 7.91	31	Pool	31,000	$ 245,210.00	$ 8.49	$ 17,949
Duke	CG	Jul-07	Purchase	-	$ -	31	G11	-	$ -	$ 8.91	$ -
Duke	Malin	Jul-07	Purchase	100	$ 6.23	31	G11	3,100	$ 19,313.00	$ 8.49	$ 7,003
Sempra	Malin	Jul-07	Purchase	1,000	$ 5.41	31	Pool	31,000	$ 167,865.00	$ 8.49	$ 95,294
Sempra	Malin	Jul-07	Purchase	1,000	$ 6.99	31	Pool	31,000	$ 216,689.99	$ 8.49	$ 46,469
Coral Energy	Malin	Aug-07	Purchase	1,000	$ 7.91	31	Pool	31,000	$ 245,210.00	$ 8.53	$ 19,189
Sempra	Malin	Aug-07	Purchase	1,000	$ 5.41	31	Pool	31,000	$ 167,865.00	$ 8.53	$ 96,534
Sempra	Malin	Aug-07	Purchase	1,000	$ 6.99	31	Pool	31,000	$ 216,689.99	$ 8.53	$ 47,709
Coral Energy	Malin	Sep-07	Purchase	1,000	$ 7.91	30	Pool	30,000	$ 237,300.00	$ 8.51	$ 18,060
Sempra	Malin	Sep-07	Purchase	1,000	$ 5.41	30	Pool	30,000	$ 162,450.00	$ 8.51	$ 92,910
Sempra	Malin	Sep-07	Purchase	1,000	$ 6.99	30	Pool	30,000	$ 209,699.99	$ 8.51	$ 45,660
Coral Energy	Malin	Oct-07	Purchase	1,000	$ 7.91	31	Pool	31,000	$ 245,210.00	$ 8.55	$ 19,809
Sempra	Malin	Oct-07	Purchase	1,000	$ 5.41	31	Pool	31,000	$ 167,865.00	$ 8.55	$ 97,154
Sempra	Malin	Oct-07	Purchase	1,000	$ 6.99	31	Pool	31,000	$ 216,689.99	$ 8.55	$ 48,329
Coral Energy	Malin	Nov-07	Purchase	1,000	$ 6.00	30	Pool	30,000	$ 180,000.00	$ 8.99	$ 89,610
Duke	Malin	Nov-07	Purchase	1,000	$ 6.93	30	Pool	30,000	$ 207,750.01	$ 8.99	$ 61,860
Duke	Malin	Nov-07	Purchase	1,970	$ 7.45	30	Pool	59,100	$ 440,294.99	$ 8.99	$ 90,837
Sempra	Malin	Nov-07	Purchase	1,000	$ 6.99	30	Pool	30,000	$ 209,850.00	$ 8.99	$ 59,760
Coral Energy	Malin	Dec-07	Purchase	1,000	$ 6.00	31	Pool	31,000	$ 186,000.00	$ 9.40	$ 105,400

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Counterparty	Delivery Point	Delivery Period	Deal Type	MMBtu per day	Price	Days In Month	End Use	Total Volume (MMBtu)	Total Cost	Market Value per MMBtu	Total Mark to Market
Duke	Malin	Dec-07	Purchase	1,000	$ 6.93	31	Pool	31,000	$ 214,675.01	$ 9.40	$ 76,725
Duke	Malin	Dec-07	Purchase	1,970	$ 7.45	31	Pool	61,070	$ 454,971.49	$ 9.40	$ 119,087
Sempra	Malin	Dec-07	Purchase	1,000	$ 6.99	31	Pool	31,000	$ 216,845.00	$ 9.40	$ 74,555
Coral Energy	Malin	Jan-08	Purchase	1,000	$ 6.00	31	Pool	31,000	$ 186,000.00	$ 9.72	$ 115,320
Duke	Malin	Jan-08	Purchase	1,000	$ 6.93	31	Pool	31,000	$ 214,675.01	$ 9.72	$ 86,645
Duke	Malin	Jan-08	Purchase	1,970	$ 7.45	31	Pool	61,070	$ 454,971.49	$ 9.72	$ 138,629
Sempra	Malin	Jan-08	Purchase	1,000	$ 6.73	31	Pool	31,000	$ 208,630.00	$ 9.72	$ 92,690
Sempra	Malin	Jan-08	Purchase	1,000	$ 6.99	31	Pool	31,000	$ 216,845.00	$ 9.72	$ 84,475
Duke	Malin	Feb-08	Purchase	1,000	$ 6.93	29	Pool	29,000	$ 200,825.01	$ 9.67	$ 79,460
Duke	Malin	Feb-08	Purchase	1,970	$ 7.45	29	Pool	57,130	$ 425,618.49	$ 9.67	$ 126,543
Sempra	Malin	Feb-08	Purchase	1,000	$ 6.73	29	Pool	29,000	$ 195,170.00	$ 9.67	$ 85,115
Sempra	Malin	Feb-08	Purchase	1,000	$ 6.99	29	Pool	29,000	$ 202,855.00	$ 9.67	$ 77,430
Duke	Malin	Mar-08	Purchase	1,000	$ 6.93	31	Pool	31,000	$ 214,675.01	$ 9.41	$ 76,880
Duke	Malin	Mar-08	Purchase	1,970	$ 7.45	31	Pool	61,070	$ 454,971.49	$ 9.41	$ 119,392
Sempra	Malin	Mar-08	Purchase	1,000	$ 6.73	31	Pool	31,000	$ 208,630.00	$ 9.41	$ 82,925
Sempra	Malin	Mar-08	Purchase	1,000	$ 6.99	31	Pool	31,000	$ 216,845.00	$ 9.41	$ 74,710
Coral Energy	Malin	Apr-08	Purchase	1,000	$ 6.75	30	Pool	30,000	$ 202,500.00	$ 7.74	$ 29,700
Coral Energy	Malin	Apr-08	Purchase	1,000	$ 7.26	30	Pool	30,000	$ 217,800.01	$ 7.74	$ 14,400
Sempra	Malin	Apr-08	Purchase	1,000	$ 6.73	30	Pool	30,000	$ 201,900.00	$ 7.74	$ 30,300
Coral Energy	Malin	May-08	Purchase	1,000	$ 6.75	31	Pool	31,000	$ 209,250.00	$ 7.48	$ 22,630
Coral Energy	Malin	May-08	Purchase	1,000	$ 7.26	31	Pool	31,000	$ 225,060.01	$ 7.48	$ 6,820
Sempra	Malin	May-08	Purchase	1,000	$ 6.73	31	Pool	31,000	$ 208,630.00	$ 7.48	$ 23,250
Coral Energy	Malin	Jun-08	Purchase	1,000	$ 6.75	30	Pool	30,000	$ 202,500.00	$ 7.53	$ 23,250
Coral Energy	Malin	Jun-08	Purchase	1,000	$ 7.26	30	Pool	30,000	$ 217,800.01	$ 7.53	$ 7,950
Coral Energy	Malin	Jul-08	Purchase	1,000	$ 6.75	31	Pool	31,000	$ 209,250.00	$ 7.57	$ 25,265
Coral Energy	Malin	Jul-08	Purchase	1,000	$ 7.26	31	Pool	31,000	$ 225,060.01	$ 7.57	$ 9,455
									$ 35,029,638.32		24,058,645

Appendix B
Electric Transaction Report
September 30, 2005

Counter party	Delivery Point	Deal Type	Delivery Period	MW	Price	On Peak Expected Hours	Off Peak Expected Hours	Total On-Peak Cost	Total Off-Peak Cost	Market Price On Peak	Market Price Off Peak	Total Mark to Market Value
Coral Power	COB	Purchase	Oct-05	25	$ 47.40	416	329	$ 492,960	$ 389,865	$ 97.00	$ 80.18	$ 785,448.82
Coral Power	NP15	Purchase	Oct-05	25	$ 36.60	416	329	$ 380,640	$ 301,035	$ 104.50	$ 78.38	$ 1,049,759.40
Sempra	NP15	Purchase	Oct-05	25	$ 54.75	416	0	$ 569,400	$ -	$ 104.50	$ 78.38	$ 517,400.00
Coral Power	NP15	Purchase	Oct-05	15	$ 59.65	416	329	$ 372,216	$ 294,373	$ 104.50	$ 78.38	$ 372,271.86
Coral Power	COB	Purchase	Nov-05	25	$ 47.40	400	320	$ 474,000	$ 379,200	$ 106.50	$ 90.35	$ 934,564.02
Coral Power	NP15	Purchase	Nov-05	25	$ 36.60	400	320	$ 366,000	$ 292,800	$ 112.25	$ 86.98	$ 1,159,532.49
Sempra	NP15	Purchase	Nov-05	25	$ 54.75	400	0	$ 547,500	$ -	$ 112.25	$ 86.98	$ 575,000.00
Sempra	NP15	Purchase	Nov-05	10	$ 56.25	400	0	$ 225,000	$ -	$ 112.25	$ 86.98	$ 224,000.00
Coral Power	NP15	Purchase	Nov-05	15	$ 59.65	400	320	$ 357,900	$ 286,320	$ 112.25	$ 86.98	$ 446,779.46
Coral Power	NP15	Purchase	Nov-05	15	$ 56.00	400	320	$ 336,000	$ 268,800	$ 112.25	$ 86.98	$ 486,199.48
Coral Power	COB	Purchase	Dec-05	25	$ 47.40	416	328	$ 492,960	$ 388,680	$ 115.00	$ 109.02	$ 1,208,324.75
Coral Power	NP15	Purchase	Dec-05	25	$ 36.60	416	328	$ 380,640	$ 300,120	$ 118.75	$ 92.24	$ 1,310,569.37
Sempra	NP15	Purchase	Dec-05	25	$ 54.75	416	0	$ 569,400	$ -	$ 118.75	$ 92.24	$ 665,600.00
Sempra	NP15	Purchase	Dec-05	10	$ 56.25	416	0	$ 234,000	$ -	$ 118.75	$ 92.24	$ 260,000.00
Coral Power	NP15	Purchase	Dec-05	15	$ 59.65	416	328	$ 372,216	$ 293,478	$ 118.75	$ 92.24	$ 529,103.59
Coral Power	NP15	Purchase	Dec-05	10	$ 66.10	416	328	$ 274,976	$ 216,808	$ 118.75	$ 92.24	$ 304,747.75
Coral Power	NP15	Purchase	Jan-06	25	$ 36.60	400	344	$ 366,000	$ 314,760	$ 121.68	$ 94.85	$ 1,351,757.08
Coral Power	NP15	Purchase	Jan-06	10	$ 58.25	400	344	$ 233,000	$ 200,380	$ 121.68	$ 94.85	$ 379,626.82
Coral Power	NP15	Purchase	Jan-06	15	$ 66.25	400	344	$ 397,500	$ 341,850	$ 121.68	$ 94.85	$ 480,160.23
Duke	NP15	Purchase	Jan-06	25	$ 66.25	400	0	$ 662,500	$ -	$ 121.68	$ 94.85	$ 554,314.52
Duke	NP15	Purchase	Jan-06	25	$ 66.25	400	0	$ 662,500	$ -	$ 121.68	$ 94.85	$ 554,314.52
BP	NP15	Purchase	Jan-06	25	$ 70.50	400	0	$ 705,000	$ -	$ 121.68	$ 94.85	$ 511,814.52
Coral Power	NP15	Purchase	Feb-06	25	$ 36.60	384	288	$ 351,360	$ 263,520	$ 120.52	$ 93.95	$ 1,218,546.61
Coral Power	NP15	Purchase	Feb-06	10	$ 58.25	384	288	$ 223,680	$ 167,760	$ 120.52	$ 93.95	$ 341,930.63
Coral Power	NP15	Purchase	Feb-06	15	$ 66.25	384	288	$ 381,600	$ 286,200	$ 120.52	$ 93.95	$ 432,255.95
Coral Power	NP15	Purchase	Feb-06	25	$ 65.50	384	0	$ 628,800	$ -	$ 120.52	$ 93.95	$ 528,216.77
Duke	NP15	Purchase	Feb-06	20	$ 79.25	384	0	$ 608,640	$ -	$ 120.52	$ 93.95	$ 316,973.42
Coral Power	NP15	Purchase	Mar-06	25	$ 36.60	432	312	$ 395,280	$ 285,480	$ 117.05	$ 91.24	$ 1,294,975.96
Coral Power	NP15	Purchase	Mar-06	10	$ 58.25	432	312	$ 251,640	$ 181,740	$ 117.05	$ 91.24	$ 356,914.37
Coral Power	NP15	Purchase	Mar-06	15	$ 66.25	432	312	$ 429,300	$ 310,050	$ 117.05	$ 91.24	$ 446,091.56
Sempra	NP15	Purchase	Mar-06	15	$ 48.50	432	312	$ 314,280	$ 226,980	$ 117.05	$ 91.24	$ 644,181.56
Sempra	NP15	Purchase	Apr-06	20	$ 54.45	400	319	$ 435,600	$ 347,391	$ 84.56	$ 61.71	$ 287,204.56
BP	COB	Purchase	Sep-06	10	$ 54.50	400	0	$ 218,000	$ -	$ 89.29	$ 72.96	$ 139,167.65
Coral Power	COB	Purchase	Sep-06	25	$ 59.50	400	0	$ 595,000	$ -	$ 89.29	$ 72.96	$ 297,919.12
Sempra	NP15	Purchase	Sep-06	10	$ 53.50	400	320	$ 214,000	$ 171,200	$ 101.56	$ 69.82	$ 244,478.38
BP	COB	Purchase	Oct-06	10	$ 54.50	416	0	$ 226,720	$ -	$ 86.41	$ 75.43	$ 132,729.56

Appendix B
Electric Transaction Report
September 30, 2005

Counter party	Delivery Point	Deal Type	Delivery Period	MW	Price	On Peak Expected Hours	Off Peak Expected Hours	Total On-Peak Cost	Total Off-Peak Cost	Market Price On Peak	Market Price Off Peak	Total Mark to Market Value
Coral Power	NP15	Purchase	Oct-06	25	$ 36.60	416	329	$ 380,640	$ 301,035	$ 94.85	$ 75.65	$ 926,999.89
Sempra	NP15	Purchase	Oct-06	10	$ 53.50	416	329	$ 222,560	$ 176,015	$ 94.85	$ 75.65	$ 244,894.94
Sempra	NP15	Purchase	Oct-06	10	$ 66.10	416	329	$ 274,976	$ 217,469	$ 94.85	$ 75.65	$ 151,024.96
BP	COB	Purchase	Nov-06	10	$ 54.50	400	0	$ 218,000	$ -	$ 85.52	$ 74.12	$ 124,061.43
Coral Power	COB	Purchase	Nov-06	25	$ 57.50	400	0	$ 575,000	$ -	$ 85.52	$ 74.12	$ 280,153.58
Coral Power	NP15	Purchase	Nov-06	25	$ 36.60	400	320	$ 366,000	$ 292,800	$ 93.87	$ 69.14	$ 833,021.35
Sempra	NP15	Purchase	Nov-06	10	$ 53.50	400	320	$ 214,000	$ 171,200	$ 93.87	$ 69.14	$ 211,528.53
Sempra	NP15	Purchase	Nov-06	10	$ 66.10	400	320	$ 264,400	$ 211,520	$ 93.87	$ 69.14	$ 120,808.54
BP	COB	Purchase	Dec-06	10	$ 54.50	400	0	$ 218,000	$ -	$ 89.08	$ 77.34	$ 138,313.99
Coral Power	COB	Purchase	Dec-06	25	$ 66.25	400	0	$ 662,500	$ -	$ 89.08	$ 77.34	$ 228,284.98
Coral Power	NP15	Purchase	Dec-06	25	$ 36.60	400	344	$ 366,000	$ 314,760	$ 97.78	$ 73.08	$ 925,544.66
Sempra	NP15	Purchase	Dec-06	10	$ 53.50	400	344	$ 214,000	$ 184,040	$ 97.78	$ 73.08	$ 244,481.85
Sempra	NP15	Purchase	Dec-06	10	$ 66.10	400	344	$ 264,400	$ 227,384	$ 97.78	$ 73.08	$ 150,737.86
BP	COB	Purchase	Jan-07	10	$ 51.50	416	328	$ 214,240	$ 168,920	$ 86.70	$ 70.25	$ 207,919.73
Sempra	COB	Purchase	Jan-07	10	$ 68.25	416	328	$ 283,920	$ 223,860	$ 86.70	$ 70.25	$ 83,299.73
Coral Power	NP15	Purchase	Jan-07	25	$ 36.60	416	328	$ 380,640	$ 300,120	$ 97.99	$ 75.28	$ 955,671.68
BP	NP15	Purchase	Jan-07	20	$ 81.50	416	0	$ 678,080	$ -	$ 97.99	$ 75.28	$ 137,231.43
BP	COB	Purchase	Feb-07	10	$ 51.50	384	288	$ 197,760	$ 148,320	$ 85.87	$ 69.58	$ 184,059.22
Sempra	COB	Purchase	Feb-07	10	$ 68.25	384	288	$ 262,080	$ 196,560	$ 85.87	$ 69.58	$ 71,499.22
Coral Power	NP15	Purchase	Feb-07	25	$ 36.60	384	288	$ 351,360	$ 263,520	$ 97.06	$ 74.56	$ 853,755.30
BP	COB	Purchase	Mar-07	10	$ 51.50	432	312	$ 222,480	$ 160,680	$ 83.39	$ 67.57	$ 187,933.76
Sempra	COB	Purchase	Mar-07	10	$ 68.25	432	312	$ 294,840	$ 212,940	$ 83.39	$ 67.57	$ 63,313.76
Coral Power	NP15	Purchase	Mar-07	25	$ 36.60	432	312	$ 395,280	$ 285,480	$ 94.26	$ 72.41	$ 902,071.14
Sempra	NP15	Purchase	Sep-07	10	$ 53.65	384	336	$ 206,016	$ 180,264	$ 96.13	$ 65.13	$ 201,690.64
Coral Power	NP15	Purchase	Oct-07	25	$ 36.60	432	313	$ 395,280	$ 286,395	$ 90.53	$ 71.16	$ 852,876.72
Sempra	NP15	Purchase	Oct-07	10	$ 53.65	432	313	$ 231,768	$ 167,925	$ 90.53	$ 71.16	$ 214,128.17
Sempra	COB	Purchase	Nov-07	10	$ 76.10	400	0	$ 304,400	$ -	$ 79.27	$ 68.57	$ 12,664.23
Coral Power	NP15	Purchase	Nov-07	25	$ 36.60	400	320	$ 366,000	$ 292,800	$ 89.59	$ 65.04	$ 757,429.80
Sempra	NP15	Purchase	Nov-07	10	$ 53.65	400	320	$ 214,600	$ 171,680	$ 89.59	$ 65.04	$ 180,211.90
Sempra	COB	Purchase	Dec-07	10	$ 76.10	400	0	$ 304,400	$ -	$ 82.57	$ 71.56	$ 25,875.24
Coral Power	NP15	Purchase	Dec-07	25	$ 36.60	400	344	$ 366,000	$ 314,760	$ 93.33	$ 68.74	$ 843,697.32
Sempra	NP15	Purchase	Dec-07	10	$ 53.65	400	344	$ 214,600	$ 184,556	$ 93.33	$ 68.74	$ 210,626.90
Sempra	COB	Purchase	Jan-08	10	$ 76.10	416	0	$ 316,576	$ -	$ 81.44	$ 65.18	$ 22,226.34
Coral Power	NP15	Purchase	Jan-08	25	$ 36.60	416	328	$ 380,640	$ 300,120	$ 91.43	$ 70.54	$ 848,498.45
Coral Power	NP15	Purchase	Feb-08	25	$ 36.60	400	296	$ 366,000	$ 270,840	$ 90.56	$ 69.87	$ 785,737.54
Coral Power	NP15	Purchase	Mar-08	25	$ 36.60	416	328	$ 380,640	$ 300,120	$ 87.94	$ 67.85	$ 790,240.99

Appendix B
Electric Transaction Report
September 30, 2005

Counter party	Delivery Point	Deal Type	Delivery Period	MW	Price	On Peak Expected Hours	Off Peak Expected Hours	Total On-Peak Cost	Total Off-Peak Cost	Market Price On Peak	Market Price Off Peak	Total Mark to Market Value
Coral Power	NP15	Purchase	Oct-08	25	$ 36.60	432	313	$ 395,280	$ 286,395	$ 84.46	$ 66.68	$ 752,286.42
Coral Power	NP15	Purchase	Nov-08	25	$ 36.60	384	336	$ 351,360	$ 307,440	$ 83.59	$ 60.94	$ 655,561.78
Coral Power	NP15	Purchase	Dec-08	25	$ 36.60	416	328	$ 380,640	$ 300,120	$ 87.07	$ 64.41	$ 752,986.58
Coral Power	NP15	Purchase	Jan-09	25	$ 36.60	416	328	$ 380,640	$ 300,120	$ 86.43	$ 66.11	$ 760,284.12
Coral Power	NP15	Purchase	Feb-09	25	$ 36.60	384	288	$ 351,360	$ 263,520	$ 85.61	$ 65.48	$ 678,467.66
Coral Power	NP15	Purchase	Mar-09	25	$ 36.60	416	328	$ 380,640	$ 300,120	$ 83.14	$ 63.59	$ 705,387.21
Coral Power	NP15	Purchase	Oct-09	25	$ 36.60	432	313	$ 395,280	$ 286,395	$ 79.85	$ 62.50	$ 669,737.28
Coral Power	NP15	Purchase	Nov-09	25	$ 36.60	384	336	$ 351,360	$ 307,440	$ 79.03	$ 57.12	$ 579,623.20
Coral Power	NP15	Purchase	Dec-09	25	$ 36.60	416	328	$ 380,640	$ 300,120	$ 82.32	$ 60.37	$ 670,396.92
Total								**$ 29,681,484**	**$ 15,686,542**			**$ 41,540,121.69**

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City of Palo Alto Utilities

Energy Risk Management Policies

For Consideration by City Council
October 2005

CITY OF PALO ALTO
UTILITIES

City of Palo Alto Utilities Energy Risk Management Policies
Table of Contents

I. INTRODUCTION

It is the policy of the City of Palo Alto, to provide reliability and affordable energy and energy services to its industrial, commercial and residential customers in an environmentally sustainable manner. Furthermore, this policy is consistent with the City's business objectives of making financially sound and timely investments in the capital infrastructure of the Utilities to ensure the reliable delivery of energy and energy services to its customers.

The Energy Risk Management Policy details the key control structures and policies for a prudent risk management processes based on sound utility risk management principles, while ensuring adherence to financial requirements set forth by City Council and Director of Administrative Services as well as all pertinent legal requirements. The control structures and policies are focused on the following issues:

- Clearly defined segregation of duties and delegation of authority
- Organizational structure for risk management controls
- Policies related to setting acceptable risk parameters and risk limits.
- Policies for risk reporting
- Permitted transaction and product types.

II. ENERGY RISK MANAGEMENT PHILOSOPHY

The mission statement of the Utilities Department is "To build value for our citizen owners, to provide dependable returns to the City and citizens of Palo Alto, and to be the preferred full service utility provider while sustaining the environment." The Utilities Strategic Plan, adopted by the Council on November 13, 2000[1] contains four supporting objectives: 1) Enhance customer satisfaction by delivering valued products and services; 2) Invest in utility infrastructure to deliver reliable service; 3) Provide superior financial performance to the City and competitive rates to customers; and 4) To identify and maintain the unique advantages of municipal ownership**.**

Palo Alto recognizes that certain risks are inherent in the deregulated energy business environment. The City seeks to minimize risks in order to provide retail rate stability to its retail customers and a stable financial return to the City's General Fund. The basic premise underlying the City's energy risk management attitude is that no activities related to energy purchase and sales should expose the City to the possibility of large financial losses in relation to the size of the electricity and gas reserve funds.

[1] Council approved the Utilities Strategic Plan on Nov. 13, 2000 (CMR:418:00) and the Utilities Strategic Implementation Plan on May 21, 2001 (CMR:223:01).

III. ENERGY RISK MANAGEMENT OBJECTIVES

The primary objectives of energy risk management activities are to balance the business objectives of (1) providing stable gas and electric rates to end users, (2) preserving a supply cost advantage through obtaining the best available price, and (3) managing business processes to allow the City to work efficiently and cost effectively.

1. Retail Rate Stability

Stable rates are of high value to the citizens and businesses in Palo Alto. However, energy commodity market prices are extremely volatile. Therefore, a primary objective is to manage the risks inherent in the energy commodity markets in which CPAU participates. The rate stability objective will be to mitigate market risk and credit risk.

Reserve balances maintained by the gas and electric utilities provide financial liquidity and flexibility in entering into other shorter-term contracts and purchases of energy in the spot and forward market as needed to meet the projected load. Maintaining the safety of these reserve funds is a matter of high priority for CPAU and the City.

2. Preserve a Supply Cost Advantage

CPAU will endeavor to: (a) reduce exposure to potential adverse energy price movements; (b) enhance revenue by taking advantage of flexibility inherent in CPAU contracts and resources; and (c) enhance revenue by offering commodity products that address customer needs and adequately cover costs.

3. Efficient and Cost Effective Business Processes

City staff will utilize business practices and controls that are sufficient to identify, evaluate, and manage risks, and are designed to streamline and minimize recording, analysis and reporting requirements. Staff will strive to improve the risk management procedures to enhance productivity, reduce the cost of conducting risk management activities, and maintain transparency and value of the risk management process.

IV. SCOPE

These Energy Risk Management Policies shall apply to the electric and natural gas supply business units as well as telecommunications business units. The electric and natural gas units are the part of the electric and natural gas enterprise funds that deal directly with the acquisition of energy supply resources.

- These Energy Risk Management Policies prescribe the management, organization, authority, processes, tools and systems to monitor, measure, and control market risks to

which the City is exposed in its normal course of business, including wholesale and retail operations, capital projects (related to generation, transmission, transportation, or storage, not distribution projects), and participation in joint powers authorities.

- The policy does not address general business risks such as fire, accident, casualty, worker health and safety, and general liability. Neither does the policy does not cover the water fund or the electric and natural gas distribution business units.

V. GENERAL TRANSACTING POLICY

1. Anti-speculation

Speculative buying and selling of energy products is prohibited. Speculation is defined as buying energy not needed for meeting forecasted load or selling energy that is not owned. In no event shall transactions be entered into to speculate on market conditions.

2. Maximum Transaction Term

The maximum term of any supply resource transaction (purchase or sale) should be ten years, unless specifically approved by the City Council, to meet long-term portfolio planning objectives.

3. Portfolio Performance and Value Reporting

Staff shall prepare performance reports containing an analysis of physical and financial positions of all electric and gas commodity contracts. The frequency and content of performance reports for each oversight body shall be prescribed in the Energy Risk Management Guidelines. Should the ratio of the market value of the portfolio to the cost of the portfolio fall outside of the risk limits prescribed in the Energy Risk Management Guidelines, the City Manager will report this fact to the City Council within a reasonable period and evaluate whether there is any risk of holding any of the contracts in the portfolio to delivery.

4. Competitive Process

Whenever possible, CPAU will obtain three or more quotations when making a purchase or sale transaction and select the best price from a responsible bidder.

VI. OVERSIGHT BODIES

1. City Council

The City Council is responsible for making high-level broad policy and strategy statements as contained in this Policy document. The Policy shall guide the general vision of CPAU business practices, articulating the City's risk philosophy, and establishing risk tolerances. The City

Council adopts the Energy Risk Management Policies as developed and recommended by the Risk Oversight Committee and delegates the City Manager to execute it. The City Council will review the Policy every year. Additionally, the City Council shall receive reports quarterly from the City Manager regarding energy risk management activities. These reports will be provided to the Council as soon as possible after the end of each quarter and no later than eight weeks following the end of the quarter.

2. Utilities Advisory Commission

The Utilities Advisory Commission (UAC) is responsible for advising the City Council on long-range planning and policy matters relating to the electricity, gas and water utilities. While it has no formal responsibility in Risk Management, the UAC does receive and review regular management reports prepared by the Risk Manager for the City Council. In addition, the UAC can serve as an important source of advice and comment to the City Council on risk management.

3. City Manager

The City Manager has overall responsibility for executing and ensuring compliance with policy adopted by the City Council. The City Manager reports quarterly to the City Council regarding energy risk management activities.

4. Risk Oversight Committee

The Risk Oversight Committee (ROC) consists of the Director of Utilities (Chairperson), the Director of Administrative Services, and the Assistant City Manager. The Senior Assistant City Attorney assigned to Utilities and the City Auditor act as non-voting advisors to the ROC. The Energy Risk Manager serves as the Secretary to the Committee.

The ROC is the primary body responsible for creating and implementing a sound approach to managing risk consistent with the business strategy and risk tolerance of the organization as defined by the City Council. As such, the ROC is critical to overseeing and reviewing the risk management process and infrastructure and managing the Utilities' risk exposure.

5. Management Oversight

Risk management oversight at an operational level is accomplished through supervisory review and approval and appropriate separation of duties. Risk management functions are separated as follows:

a. Front Office – Planning and Procurement

The Front Office is primarily responsible for resource planning and procuring energy supplies and services. The Front Office oversight role is accomplished through supervisory review and approval.

b. Middle Office – Controls and Reporting

The Middle Office provides the primary independent management oversight role. The Middle Office institutes, supervises, and reviews all risk management activities including portfolio exposure, credit exposure, transaction compliance and on-going approval of counterparties and transacting precuts. The Middle Office responsibilities include monitoring CPAU's risk exposures and ensuring compliance with policies, guidelines, and procedures. Additionally, the Middle Office is responsible for reporting to the ROC on Risk Management issues, and recommending to the ROC when changes in policy or operating procedure are required. These recommendations may relate to the temporary or permanent halting of transactions with one or more counterparties, exceptions to rules and procedures, other operational exceptions, and any other topic the Risk Manager believes represents an unacceptable risk exposure.

The Middle Office adopts and updates as necessary the Energy Risk Management Policies, Guidelines and Procedures so that portfolio management functions occur in compliance with the Council-adopted Energy Risk Management Policies and ROC-adopted Energy Risk Management Guidelines. The functions of the Middle Office can be broadly defined as Quantitative Analysis, Compliance Review, Credit Administration, and Management Reporting.

Quantitative Analysis
The Middle Office performs rigorous risk analysis to evaluate the risk exposure on both a transaction and portfolio basis.

Compliance Review
The Middle Office monitors all transactions to ensure compliance of transactions with the Risk Management Policies, Guidelines and Procedures.

Credit Administration
The Middle Office monitors counterparty creditworthiness. The Middle Office objectively measures and monitors credit limits and credit histories, and may temporarily or permanently halt trading, upon recommendation of the ROC, with an approved counterparty because of credit exposure or credit condition.

Management Reporting
The Middle Office administers reports to the ROC related to risk management, and performance in alignment with the Energy Risk Management Policies and Guidelines and the requests of the ROC.

c. Back Office – Settlement and Recording

The Back Office is primarily responsible for settlement of bills, recording transactions, bookkeeping and accounting, and contract administration. The Back Office roles in oversight are ensuring that bills reflect orders, independently monitoring and recording transactions into a tracking database, and verifying and reporting on compliance with procedures as reflected in the deal tracking documentation. Functions within the Back Office are performed by both ASD and CPAU personnel and are detailed in the Risk Management Procedures.

VII. CUSTOMER CONTRACT POLICY

Guidelines for oversight, review, approval, pricing, and reporting of customer contracts and fixed-term commodity rates are necessary to ensure staff is implementing contracts as directed by Council and contained within the CPAU Rules and Regulations of the City of Palo Alto Utilities #5, Section D.

VIII. COMMODITY PRICING POLICY

1. Policy Statement

Retail prices for energy supplies will be fair and equitable to all customers and will recover all incurred costs. The commodity pricing policy will be used both for the development of standardized commodity tariffs and for long-term, or customized, customer contract rates. The City Manager is responsible for implementing this policy by overseeing the process of all commodity rate development and ensuring that all procedures are followed consistently and that all calculations are appropriately documented.

The commodity pricing policy is composed of the following five principles with the first principle having priority over the remaining four:

a. Direct Cost Recovery

All direct costs of providing commodity service will be recovered in commodity rates.

b. Risk Management

To the extent practicable, all risks must be insured, and contract terms must protect CPAU from major contingencies. To the extent that CPAU assumes risk to provide commodity products to customers, the customer shall pay reasonable compensation for bearing that risk.

c. Indirect Cost Recovery

To the extent practicable, it is an objective to recover all indirect costs of commodity service from commodity customers.

d. Nondiscrimination

All customers within a customer class shall be treated in a fair and impartial manner and be entitled to acquire commodities at the same or substantially similar terms and conditions.

e. Nonsubsidization

To the extent practicable, costs will be allocated to customers and customer classes according to how those costs are incurred. Thus, commodity rates will not be established in a manner that permits one class of customers to be subsidized by another.

IX. COUNTERPARTY CREDIT POLICY

1. Objectives

The objective of the Counterparty Credit Policy is to minimize the potential adverse financial impacts on the City in the event of a defaulting counterparty. The policy is to minimize the City's credit exposure and potential adverse financial impacts by:

- Establishing a credit risk management governance and oversight structure within the existing energy risk management program;
- Providing a framework to enable the City to qualify energy suppliers and transact with approved counterparties;
- Providing counterparty transacting parameters (limits) to control and measure the City's exposure to any one supplier; and
- Implementing a mechanism to monitor and report on supply portfolio related counterparty credit exposures.

This policy applies to market-based commodity transactions as well as to physical asset-based transactions related to generation, transmission, gas wells, pipeline capacity, natural gas storage, etc.

2. Organizational Roles and Responsibilities

The Middle Office has the responsibility to ensure that energy procurement transacting activities and supply portfolio management conform to the Counterparty Credit Policy.

3. Guidelines to Qualify Suppliers

Counterparty credit risk management involves selecting reputable companies to supply the City and allocating purchases amongst multiple suppliers. The guidelines set out qualification

criteria for potential counterparties of the City. The ROC maintains a list of approved counterparties.

4. Assignment of Transaction Limits and Credit Exposure Limits to Counterparties

The ROC approves the Counterparty Credit Limits proposed by the Risk Manager and ensures that such limits diversify the credit exposure of the City as it relates to energy supply procurement activities. Transaction and Credit Exposure Limits are established by evaluating a counterparty's credit worthiness, net worth of assets held by the counterparty, quality of guarantees, market intelligence, and credit enhancement tools provided by counterparty, as set forth in the Energy Risk Management Guidelines.

5. Monitoring and Reporting on the Counterparty Credit Exposures

Counterparty credit exposures and transactions volumes relative to the established limits are to be monitored on an ongoing basis and reported to the ROC on a monthly basis by the Risk Manager.

X. POLICY REVIEW AND REPORTING ON TRANSACTING

Key to energy risk management is the monitoring of risks. Accurate and timely information must be provided to all parties involved in any aspects of energy risk management to allow them to perform their functions appropriately. Quarterly reports will be provided for distribution to the ROC, the UAC, and the City Council which provide details on the City's forward purchases, market exposure, credit exposure, transaction compliance and other relevant data.

XI. AUTHORIZED TRANSACTING PRODUCTS

Products allowed for electric transactions include energy, capacity, transmission, and ancillary services. Products allowed for natural gas transactions include energy, transportation, and storage. The Risk Oversight Committee is responsible for authorizing all products and commodity types as further detailed in the Energy Risk Management Guidelines. At this time, only physical transacting products are approved. Financial products are explicitly prohibited. Transactions of products not approved by the Risk Oversight Committee are strictly prohibited. All transactions must follow certain requirements as described throughout this Policy. Key elements of CPAU's transaction policy are as follows:

- All transactions must be committed to by authorized transacting personnel.
- All transactions must be with approved counterparties with executed and Council approved contracts.
- All transactions must be with counterparties with adequate available credit.
- All transactions must be committed over recorded phone lines or via electronic mail.

- All transactions must be Approved Transaction Types.
- All transactions must be consistent with Risk Management Policy as described in this document, as well as Risk Management Guidelines and Procedures.

Failure to observe the above minimum requirements when executing energy transaction is a violation of Policy and is subject to disciplinary action.

XII. TRANSACTING AUTHORITY

The City Manager has the authority to purchase and sell wholesale energy commodities for terms of up to three years under open purchase contracts. The Director of Utilities is granted the authority to negotiate for the purchase and sale energy commodities. Purchases and sales are subject to signature authority limits as defined in the Municipal Code. Currently, energy purchases exceeding $250,000 per year and exceeding a three-year term require City Council approval (Municipal Code Sec *2.30.210 (l)*). Authority to enter into transactions must be based on City Council approved contracts such as master agreements, purchase agreements, or other contractual forms. In all cases the Municipal Code provides the final authorization rules and regulations for energy purchases.

City Manager authorities may be delegated by the City Manager. Authorization levels for City staff as delegated are maintained in the Risk Management Procedures manual by the Middle Office. The City Clerk maintains the list of individuals authorized to make wholesale transactions.

XIII. CONFLICT OF INTEREST

In accordance with the Municipal Code and California law, personnel involved in transacting and oversight of the Utilities supply resource acquisition programs may not engage in financial conflicts of interest, unless the City is duly informed and it elects to waive such conflicts. The Energy Risk Management Guidelines contain detailed requirements for staff conflict of interest disclosure and prohibitions as to acquiring or maintaining financial interest in energy trading counterparties. All personnel in procuring or selecting counterparties for contracting or transacting are required to complete, on an annual basis, the Form 700 Disclosure forms and submit these forms to the City Clerk. Utilities Department senior management are responsible for routinely reviewing the Form 700 of each staff member engaged in the supply resource decision-making process for the purpose of identifying potential financial conflicts of interest. The City Attorney's Office will assist Utilities Department senior management in reviewing these forms and providing legal advice in connection with such reviews.

MEMORANDUM

3

TO: **UTILITIES ADVISORY COMMISSION**

FROM: **UTILITIES DEPARTMENT**

DATE: **MAY 4, 2005**

SUBJECT: **RECOMMENDATION TO AFFIRM THE CONTINUED APPLICATION OF THE 2003 ELECTRIC AND GAS SUPPLY RATE STABILIZATION RESERVE GUIDELINES**

RECOMMENDATION

This report requests that the Utilities Advisory Commission (UAC) recommends that the Council affirm the continued application of the 2003 Electric and Gas Supply Rate Stabilization Reserve (RSR) Guidelines by staff for financial planning and retail rate making purposes.

EXECUTIVE SUMMARY

City of Palo Alto Utilities (CPAU) annually evaluates the reserve levels required to maintain the financial health of CPAU and to maintain stable rates for our customers. The methodologies for determining Maximum and Minimum Guidelines for the Electric and Gas Supply RSRs were most recently updated and approved in 2003 (CMR: 483.03). Based upon the most recent review of uncertainties, staff recommends the continued application of the 2003 Reserve Guidelines which set the Minimum and Maximum Supply RSR levels as a function of budgeted annual supply purchase costs. Staff also recommends maintaining the Electric Supply RSR balance close to the Maximum end of the guideline in FY 05-06 due to increased regulatory and legal uncertainties. Since natural gas pool supply cost in FY 05-06 are known with a high degree of certainty, staff recommends the Gas Supply RSR balance for the year be allowed to drift closer to the Minimum end of the Guideline.

Table 1 shows FY 05-06 minimum and maximum reserve levels for the electric and gas supply RSR based upon currently approved guidelines and budgeted cost for FY 05-06. The water, wastewater, and electric and gas distribution RSRs based upon approved guidelines are also shown.

Table 1 -Current RSR Guideline Levels Million $

RSR	Current 05-06 Guidelines Min/Max	Current Formula to Calculate Maximum Guideline (Minimum Guidelines = 50% of Max)
Electric Supply	29.9 / 59.8	103% of purchase costs
Gas Supply	7.6 / 15.2	75% of purchase costs
Electric Distribution	5.3 / 10.6	38% of sales revenue
Gas Distribution	3.0 / 5.9	40% of sales revenue
Water	7.9 / 15.8	62% of sales revenue
Wastewater Collection	4.6 / 9.1	61% of sales revenue

BACKGROUND

In 1993, Council adopted a Utility reserve policy and approved establishing Rate Stabilization Reserves to help stabilize rates for each Utility (CMR:263:93). The key points of the policy are:

- Reserves should be used to finance extraordinary one-time contingencies and to cover increased operating costs in the short-run, while allowing rates to gradually increase over a reasonable period.

- Reserves should not be used to solve long-term financial problems or to cover potential major catastrophic disasters.

- Rate Stabilization Reserve (RSR) level guidelines should be set to allow reserves to float up or down. The decision to hold more money or less money than the guideline should be based on an assessment of the uncertainties and financial risk facing the utilities.

- The adequacy and prudence of the guidelines will be reviewed internally each year, and if appropriate, revised guidelines will be recommended.

Since 1993, Council has revised certain RSR guidelines in 1998 (CMR:194:98), 2001 (CMR: 248:01), and in 2003 (CMR: 483.03). Currently, the Water and Wastewater Funds each have one RSR to cover supply and distribution costs. To assure fairness to all ratepayers in a deregulated competitive environment, separate RSRs for supply and distribution were established for the Electric and Gas Funds.

DISCUSSION

Prudent reserve levels reduce the need for unplanned rate changes by providing a cushion to fund unanticipated cost contingencies. In this manner, reserves help to provide rate stability. Prudent reserve levels also help to maintain the City's excellent credit rating. Standard and Poors (S&P) and Moody's assigned an AA- and Aa3 rating, respectively, to the City's 2002 Utility Revenue Bonds. S&P noted, "In addition to rate increases, the city has established cash reserve policies for each utility fund that provide a significant amount of liquidity." S&P further noted, "The stable outlook reflects a demonstrated commitment on behalf of management and the City Council to maintain the financial health and flexibility of the utility funds." In September 2004 S&P affirmed City's "AA- stable" rating.

In recent years the compounded impacts of regulatory and legal uncertainties, a sluggish economy, volatile energy prices, and rising capital improvement costs (CIP) related to CPAU's aging infrastructure have posed challenges in maintaining stable retail rates and reserves. It is important to have flexibility to delay rate increases or decreases in order to stagger retail rate adjustments between the six utilities on a customer's bill. The value and importance of having adequate reserves to weather an unanticipated crisis was demonstrated during the 2000-01 energy crisis as Gas Fund reserves were drawn down to near zero in order to cushion the rate shock to CPAU customers from skyrocketing wholesale natural gas costs.

Starting in January 2005, reduced electricity available from the Western contract along with the variability in hydro energy production has exposed the Electric Supply RSR to significant market

price risk, particularly in low-hydro production years. These uncertainties were addressed in the Long Term Electric Acquisition Plan (LEAP) Guidelines and Implementation plan.

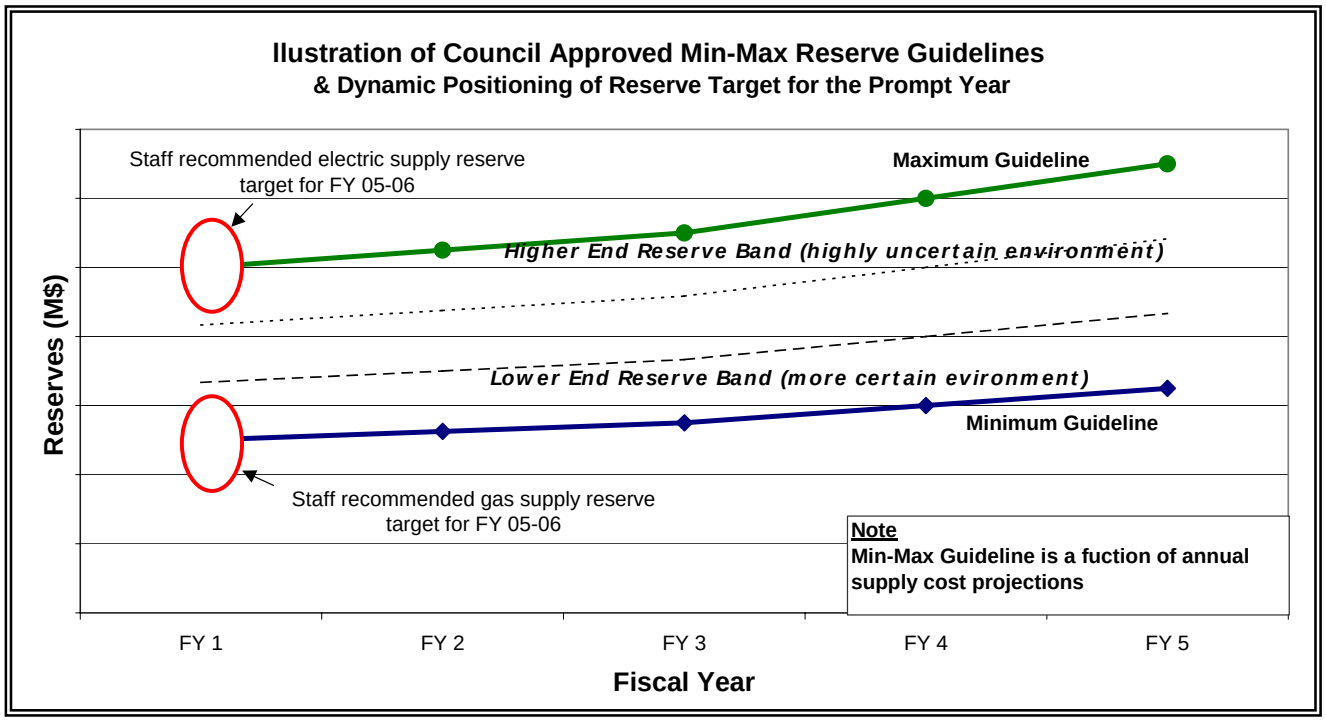
LEAP Guideline #2 – CMR:398:02, October 21, 2002
Manage hydro production risk by maintaining adequate supply rates stabilization reserve

LEAP Implementation Plan #11 – CMR:354:03, August 4, 2003
Maintain adequate reserves by recognizing the degree of uncertainty the City faces in the future. Evaluate modifying the policy or targets to make certain that the Electric Supply RSR is adequate to ensure stable rates in an environment of uncertainty and consider potential guidelines such as being able to maintain stable rates in the event of two dry years in a row.

Summary of Uncertainty Analysis and Determination of FY 05-06 Target Reserve Levels

The current goal of the Electric and Gas Supply RSR is to have sufficient funds to cover two broad situations over a generic two year period: (1) Volatility in recurring supply costs, and (2) one-time cost contingencies. Having sufficient reserves allows rate stability and rate flexibility to be maintained over a two-year period. After two years, it is assumed that rates would be changed to cover any on-going cost or revenue changes. The categories of cost uncertainties provided in the updated analysis maintained the same broad cost categories identified in the 2003 study. The summary of analysis results along with comparative results from the 2003 study is shown in Table 2 for electric and Table 3 for natural gas. A more detailed analysis is provided in Attachment A.

In establishing targets for the Supply RSR balances, staff assessed the cost uncertainty for FY 05-06 to determine where relative to the Minimum and Maximum Guidelines. This concept of determining dynamic reserve level targets for the prompt year is illustrated below.



Electric Supply RSR

The analysis revealed a considerable increase in cost uncertainties faced by the electric supply business unit. Compared to the $53.5 million cost uncertainties identified in the 2003 analysis, present analysis revealed a cost uncertainty of $76.8 million. Higher market prices, greater hydro production exposure, and high degree of legal and regulatory risks are the major causes of the rise in uncertainty. Much of this higher legal and regulatory uncertainty is expected to dissipate by the end of FY 05-06. Hence it is recommended to maintain the existing Council approved Electric Supply RSR Minimum and Maximum Guideline range of 51.5% to 103% of budgeted supply purchase cost. Further, due to the high degree of cost uncertainty in FY 05-06, maintaining reserves at their present level, close to the Maximum Guideline, appears prudent.

Table 2: Summary of Electric Supply Cost Uncertainties (Million $)

Categories of Cost Uncertainties	2005	2003
A. Variable Retail Sales Volume/Revenue	0	0
B. Recurring Cost Uncertainty		
1. Western hydro production and market price variability (2 dry hydro years)	20.5	18
2. Calaveras hydro production – market price (2 dry hydro years)	14.5	4.0
3. Calaveras Plant outage – loss of production (1 occurrence)	1.0	1.5
4. Market price risk - related to un-hedged load positions (2 years)	12.5	5.0
5. CAISO/transmission costs (2 years)	4.3	4.0
Subtotal (A and B)	*52.8*	*32.5*
C. One-time Cost Contingencies		
6. Regulatory and legal cost uncertainties	18.0	10
7. Supplier default (1 occurrence)	6.0	6.0
8. Thermal plant investment initial working capital	0	5.0
Subtotal (C)	$ 24.0	21.0
Sum (A) (B) and (C)	76.8	53.5
Electric Supply RSR Minimum/Maximum Guideline FY 2005-06	29.9 / 59.8	N/A
Projected reserve beginning balance July 1, 2005	56.1	N/A

Gas Supply RSR

Analysis of the gas supply cost uncertainties and RSR requirements revealed that the $12.2 million cost uncertainty identified in the 2003 analysis has now dropped slightly to $11.5 million. This drop is mainly a result of staff decision not to provide reserves to cushion an increase in gas pool customer loads. The market price risk for the un-hedged pool load scenario has increased with increasing market prices. The analysis also revealed that the 2003 Council approved Minimum and Maximum Guideline range of 37.5% - 75% of budgeted supply purchase cost is still valid.

Since a large part of the pool load has been purchases at known cost for FY 05-06, they cost uncertainty for FY 05-06 is much smaller than the scenario evaluated above. Hence, Gas Supply RSR levels for FY 05-06 should be close to the Minimum Guideline level of $7.6 million.

Table 3: Summary of Gas Supply Cost Uncertainties (Millions $)

Categories of Cost Uncertainties	2005	2003
A) Variability in Retail Sales Volume	0	2.4
B) Recurring Cost Uncertainty - Market Price – un-hedged pool loads for two years	8.5	6.8
C) One-Time Cost Contingency	3.0	3.0
Sum (A) (B) and (C)	11.5	12.2
Gas Supply RSR Minimum/Maximum Guideline FY 2005-06	7.6 / 15.2	N/A
Projected reserve beginning balance July 1, 2005	7.5	N/A

RESOURCE IMPACT

Council affirming the continued application of the currently approved Maximum and Minimum Supply RSR Guidelines will not automatically trigger a rate increase or decrease as retail rate changes may only be approved by Council. When approving retail rate changes Council may consider the projected reserve balances and related RSR guidelines.

ALTERNATIVES

The current supply reserve policy is to hold adequate funds to mitigate the cost uncertainties and contingencies anticipated over a two-year period without having to resort to an immediate rate increase. An alternative is to maintain minimal cash in reserves and adjust rates as needed to cover cost uncertainties as they manifest. Both approaches are equally valid, but the alternative to the current policy reduces the ability of reserves to hold rates stable and may not comport with Council's objective of providing stable rates.

POLICY IMPLICATIONS

Affirming the current Electric and Gas Supply Rate Stabilization Reserve Guidelines does not represent a change to existing policies. Staff's proposal meets the following Utilities Strategic Plan objective to "provide superior financial service to the City and competitive rates to customers".

ENVIRONMENTAL REVIEW

The adoption of the resolution does not constitute a project under the California Environmental Quality Act; therefore, no environmental assessment is required.

ATTACHMENT

Detailed Analysis of Electric and Gas Supply Cost Uncertainties – 2005 Update

PREPARED BY: Karla Dailey, Lucie Hirmina, Monica Padilla, Shiva Swaminathan

REVIEWED BY: **TOM AUZENNE,** Assistant Director, Utilities Customer Services

DEPARTMENT HEAD: _____

JOHN ULRICH
Director of Utilities

Attachment A: Detailed Analysis of Generic Supply Cost Uncertainties – 2005 Update

Update of Electric Supply Cost Uncertainties & Contingency Reserve Needs
Cost uncertainties identified for the electric supply portfolio totaling $ 76.8 million are tabulated below followed by a discussion of the uncertainties.

Summary of Electric Supply Cost Uncertainties

Categories of Cost Uncertainties	Million $
A. Variable Retail Sales Volume/Revenue	$ 0
B. Recurring Cost Uncertainty	
1. Western hydro production and market price variability (2 dry hydro years)	20.5
2. Calaveras hydro production – market price (2 dry hydro years)	14.5
3. Calaveras Plant outage – loss of production (1 occurrence)	1.0
4. Market price risk - related to un-hedged load positions (2 years)	12.5
5. CAISO/transmission costs (2 years)	4.3
Subtotal (A and B)	*52.8*
C. One-time Cost Contingencies	
6. Regulatory and legal cost uncertainties	18.0
7. Supplier default (1 occurrence)	6.0
8. Thermal plant investment initial working capital	0
Subtotal (C)	$ 24.0
Sum (A) (B) and (C)	76.8
Electric Supply Rate Stabilization Reserve Minimum/Maximum Guideline FY 2005-06	29.9 / 59.8
Projected reserve beginning balance July 1, 2005	56.1

A. Variable Retail Sales Volume
Retail sales volume may vary due to the economic climate, conservation, price elasticity and/or weather. In the event of lower sales volume, surplus energy purchases may be sold into the market with minimal or no net impact on overall Supply revenues. Weather related higher loads create mainly a capacity/transmission and reliability issue, thought market prices tend to be higher during the period. With the ability to shape Calaveras and Western energy in to peak load periods, CPAU has flexible resources to meet short-term spikes in load. A sustained load surge along with high market prices will adversely affect the supply costs. However, this will result higher distribution sales revenue. Hence, no reserves are recommended to cover this uncertainty in the Supply RSR.

B. Recurring Cost Uncertainties

1. Western Hydro Production and Market Price Variability = $20.5 million
   Western energy is expected to provide ~40% of the City's energy needs in an average hydro year. However, Western energy could vary between 25-55% of City's energy needs depending on hydro conditions at a 10%-90% probability exceedence level. Assuming market prices and hydro conditions are negatively correlated, the supply cost variability was computed. A maximum reserve target of $20.5 million was recommended to cover two consecutive dry hydro years. (90 percentile dry hydro scenario for two years). The probability of consuming the 20.5 million in any two-year period is approximately 10%.

Lower than average energy production forecasts for FY 05-06 based on the 2004/05 hydrological year reduces the need to carry full reserves in FY 05-06 as it is not expected that energy production will be much lower than the current low projections. Further, staff is evaluating a complementary energy exchange product with existing suppliers to help reduce hydro cost uncertainty in the future and may result in reducing the need to carry large reserves.

2. Calaveras Hydro Production – Market Price Uncertainty = $14.5 million
   Palo Alto's share of Calaveras hydro production from 2005 forward is expected to meet ~12% of the City's energy needs in an average hydro year. This could vary between 4-22% of the City's energy needs depending on hydro conditions at a 10%-90% probability level. Assuming market prices and hydro conditions are negatively correlated, the supply cost variability was computed. A maximum reserve target of $14.5 million is recommended to cover two consecutive dry hydro years (90% percentile dry hydro scenario for two years). The probability of consuming the $14.5 million in two years is estimated at approximately 10%.

   Since CY 2005 production is expected to be 125% of average, the reserve needs related to this contingency for FY 05-06 are expected to be low as it is unlikely that the hydro generation from Calaveras will be at a dry hydro year level in FY 05-06.

3. Calaveras Plant Outage = $1 million
   Value loss related to plant outage will be greatest if the plant loss occurs during the uncontrolled run-offs in the spring months and the plant is forced to spill water. Value of lost production/spill during the spring months is valued at ~$1 million if the outage lasts for two months. Since the plant insurance coverage against lost production does not begin until the 3rd month of outage, a reserve level of $1 million is recommended to be maintained to cover this contingency. NCPA Plant insurance is expected to cover most of the additional low probability/high impact contingencies related to plant outages. Though the probability of plant outage is < 1%, the probability of consuming this reserve for other plant related events is difficult to quantify.

4. Market Price Risk - Related to Un-hedged Load Positions = $12.5 million
   The Short-Term Electricity Acquisition Plan (STEAM) developed by staff sets parameters for procuring supplies from the market over a 3-year rolling window to meet load. This laddered purchase strategy could result in 20% open position in Year 1 and a 30% open Year 2 if purchases are made at the lower end of the STEAM guidelines.

   If market prices increase rapidly, when the City has not procured all electric supply needs, the budgeted cost over 2 years has the potential to increase by $12.5 million (average of 250 GWh/year over two years experiencing a $25/MWh price increase). A $12.5 million maximum reserve to cover this contingency has been included. The probability of consuming the $12.5 million in two years is estimated at around 10%.

   For FY 05-06, close to 90% of needed supply has been purchased, and hence the reserves requirement for the year is projected to be less than $2 million.

5. CAISO/Transmission Cost Uncertainty = $4.3 million

This relates to ancillary services available through Western as well as transmission, reliability service charges, and ISO costs. A $4.3 million maximum reserve level has been included to cover this uncertainty. With the ever-changing market-design proposals, the probability of consuming the full extent of the reserve is difficult to quantify.

C. One-Time Cost Contingencies

6. Miscellaneous Regulatory Uncertainties = $18 million

   Regulatory and legal uncertainties are numerous and difficult to quantify. Historically, the potential for contested issues between CPAU and other parties has existed. CPAU has been involved in a number of litigation events and others could arise in the future. Examples include events such as various regulatory rulings that could allow miscellaneous PG&E cost pass-through to NCPA and Western, and CVP cost allocation issues related to Western energy rates. Although there is a high degree of uncertainty surrounding potential outcomes of regulatory rulings, disputes, and litigation, it is appropriate to provide funds in the Electric Supply RSR. A nominal reserve of $18 million is estimated to cover adverse regulatory and legal outcomes. The $18 million estimate is primarily to cover regulatory uncertainty related to PG&E-Western dispute, and does not include legal uncertainties. The probability that the full extent of this reserve will be consumed in FY 05-06 is very high.

7. Supplier Default = $6 million

   CPAU's current credit exposure with its four electric suppliers is $19 million, though the probability that one of the suppliers would default on the supply contract and force CPAU to purchase that counterparty's supply commitments from the open market is less than 1%. However remote the probability of such an occurrence at the present time, the impact of such an event could be high and reserves will be managed with this in mind. A $6 million maximum reserve level, similar to the 2003 study levels, has been included to cover this uncertainty. The $6 million is to cover the mark-to-market value of the defaulting supplier commitments to CPAU. The full extent of this reserve is unlikely to be consumed in FY 05-06.

8. Thermal Plant Investment Initial Working Capital = $0 million

   In accordance with Council approved LEAP Guidelines, staff is pursuing thermal plant investments/acquisition opportunities. Though initial working capital cost related feasibility studies, potential land acquisition, pollution air credit purchases, and related costs may be incurred, no specific reserve levels are recommended at this time. The 2003 analysis had provided for a $5 million working capital reserve.

Update of Gas Supply Cost Uncertainties and Contingency Reserve Needs

Cost uncertainties identified for the gas supply portfolio totaling $ 11.5 million are tabulated below followed by a discussion of the uncertainties. The current guideline formulas appear to be adequate to address these uncertainties.

Summary of Gas Supply Cost Uncertainties

Categories of Cost Uncertainties	Million $
A) Variability in Retail Sales Volume	0
B) Recurring Cost Uncertainty - Market Price – un-hedged pool loads for two years	8.5
C) One-Time Cost Contingency	3.0
Sum of 1,2, 3	11.5
Gas Supply Rate Stabilization Reserve Minimum/Maximum Guideline FY 2005-06	7.6 / 15.2
Projected reserve beginning balance July 1, 2005 (per proposed budget)	7.5

The current guideline formulas appear to be adequate to address volatile gas market prices.

A. Variability in Pool Retail Sales Volume = $0

For the Gas Fund Supply RSR, a volumetric rise rather than a sales decline is a situation that can cause a reserve withdrawal. If pool loads are higher than expected, additional supplies must be purchased at prevailing market prices. If market prices are high, the result is a decrease in net revenue for the pool and a withdrawal from the Gas Supply RSR. $2.4 million in reserves protects the City from net revenue declines over two years. However, since a surge in sales volume will increase distribution sales revenue, no reserves are recommended at this time.

B. Market Price Risk = $8.5 million

The gas commodity laddering strategy (CMR:196.01 and 167:04) leaves some exposure to un-hedged portions of the pool load at the time that the purchased gas cost budget is developed. According to the gas laddering strategy, 40% to 60% of the load may be exposed to market prices over 2 years, though staff tend to maintain the exposure closer to an average of 20-30% over the next 2 years.

If on average supply for 50% of the pool load remains un-hedged over a 2 year period, and a rapid market price increase is experienced, staff estimate costs over 2 years could increase by as much as $8.5 million (50% of 2.64 million MMBtu/year * 2 years * a $3.25/MMBtu increase in market price). A reserve level of $8.5 million is recommended to cover this contingency. With the laddering strategy the probability on consuming $8.5 million over 2 years is estimated at 10%.

Close to 90% of pool loads have purchases for FY 05-06, hence the market price uncertainty in the coming year is less than $1 million.

C. One-Time Cost Contingency = $3.0 million

Such contingencies could be regulatory and legal cost uncertainties as well as supplier default/credit risk. Suppler default/credit risk is the risk that one or more of CPAU's gas suppliers would default on fixed-price gas delivery. CPAU's current credit exposure with its five gas suppliers is $5.7 million, though the probability that one of the suppliers would default is less than 1%.

Several uncertain regulatory and legal outcomes also exist. A nominal reserve of $3 million is estimated to cover adverse regulatory, legal and supplier default/credit risk. The overall probability of consuming the full extent of this reserve in FY 05-06 is estimated to be very high.

Quarterly Financial Report for Electric Utility

City Council Shirtsleeve Session

11/15/2006

Background

- Electric Department financial position was presented to council on October 18, 2005
  - Revenues & Expense Financial Structure
  - Discussion of net open position procurement
  - Discussion of power supply revenues and expenses
- Financial Plan Process was Presented
  - Stabilizing purchased power costs in the short term
  - Correcting Revenue/Expense imbalances through application of a MCA
  - Implementing a long term rate structure and financial plan

Issue

- Long term financial plan includes a risk management program
  - Reporting
    - What is reported
    - Who prepares
  - Procurement strategies
    - Ex: Palo Alto uses a laddering strategy purchasing up to 100% of forecasted load for upcoming 18 months, up to 75% of load for 19 to 29 months out and up to 50% of load for 27 to 36 months out
  - Authorization limits/checks and balances

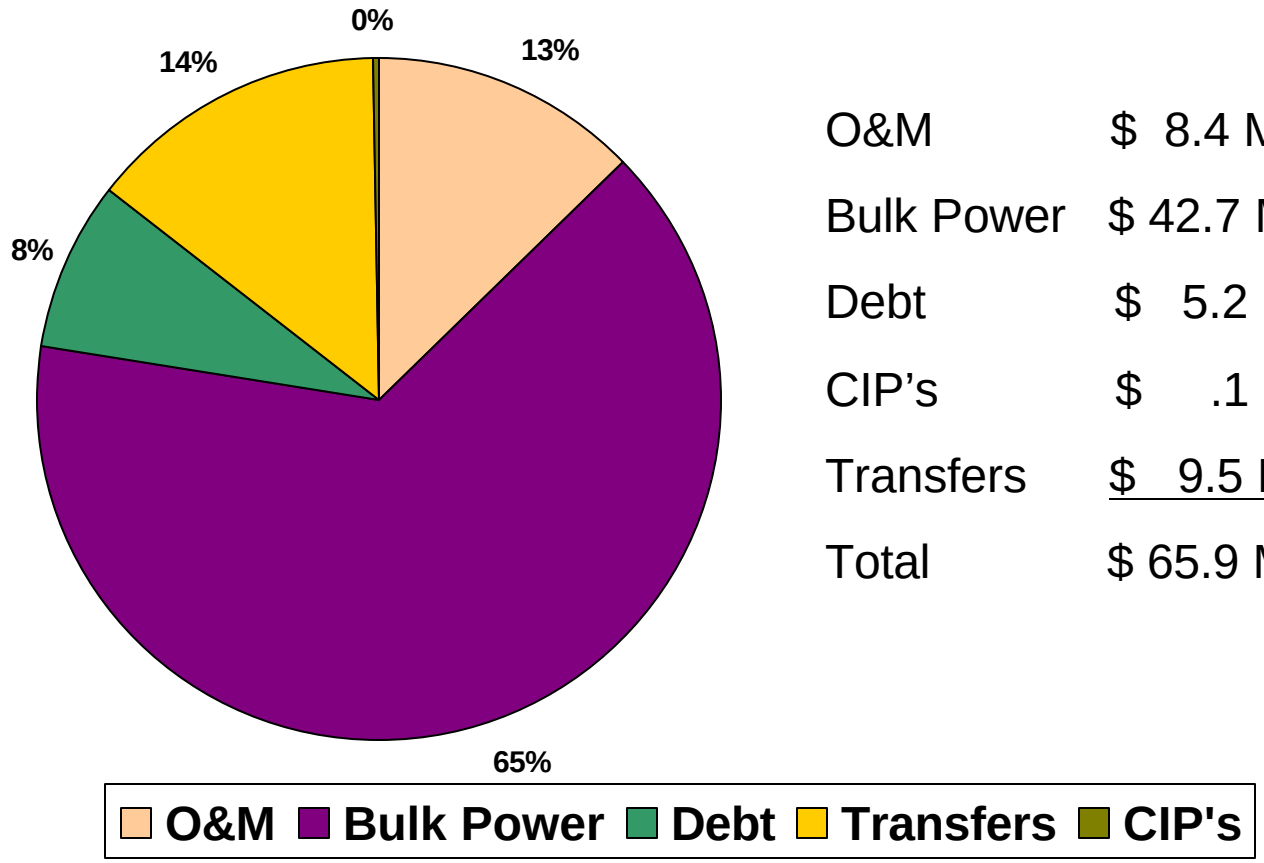
Issue (Cont)

- Until Long term financial plan is completed our goal is to begin establishing a culture of providing quarterly oversight reports to council
- Today we are providing:
  - Electric Utility Proforma
  - Net Open Positions FY06 and FY07
  - Summary of rate and MCA revenue
  - Summary of Market Transactions by Month
  - Example Risk Management Report from Palo Alto

Issue

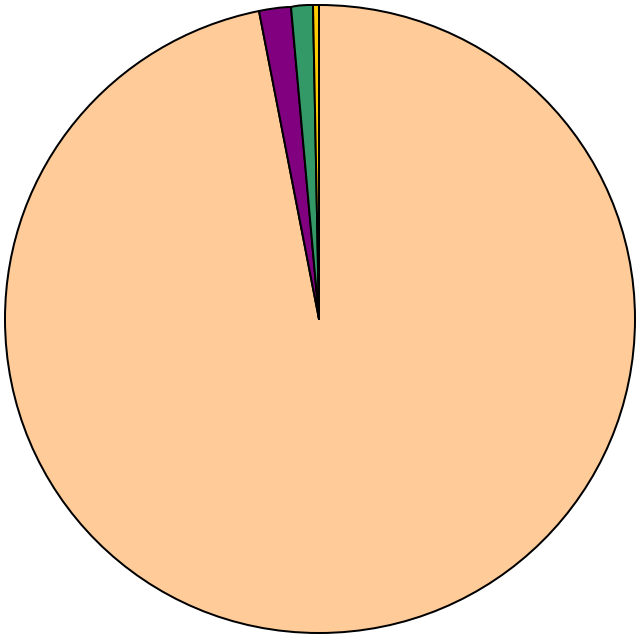
Questions/Discussion

Financial Structure - Expenses



O&M	$ 8.4 Million
Bulk Power	$ 42.7 Million
Debt	$ 5.2 Million
CIP's	$ .1 Million
Transfers	$ 9.5 Million
Total	$ 65.9 Million

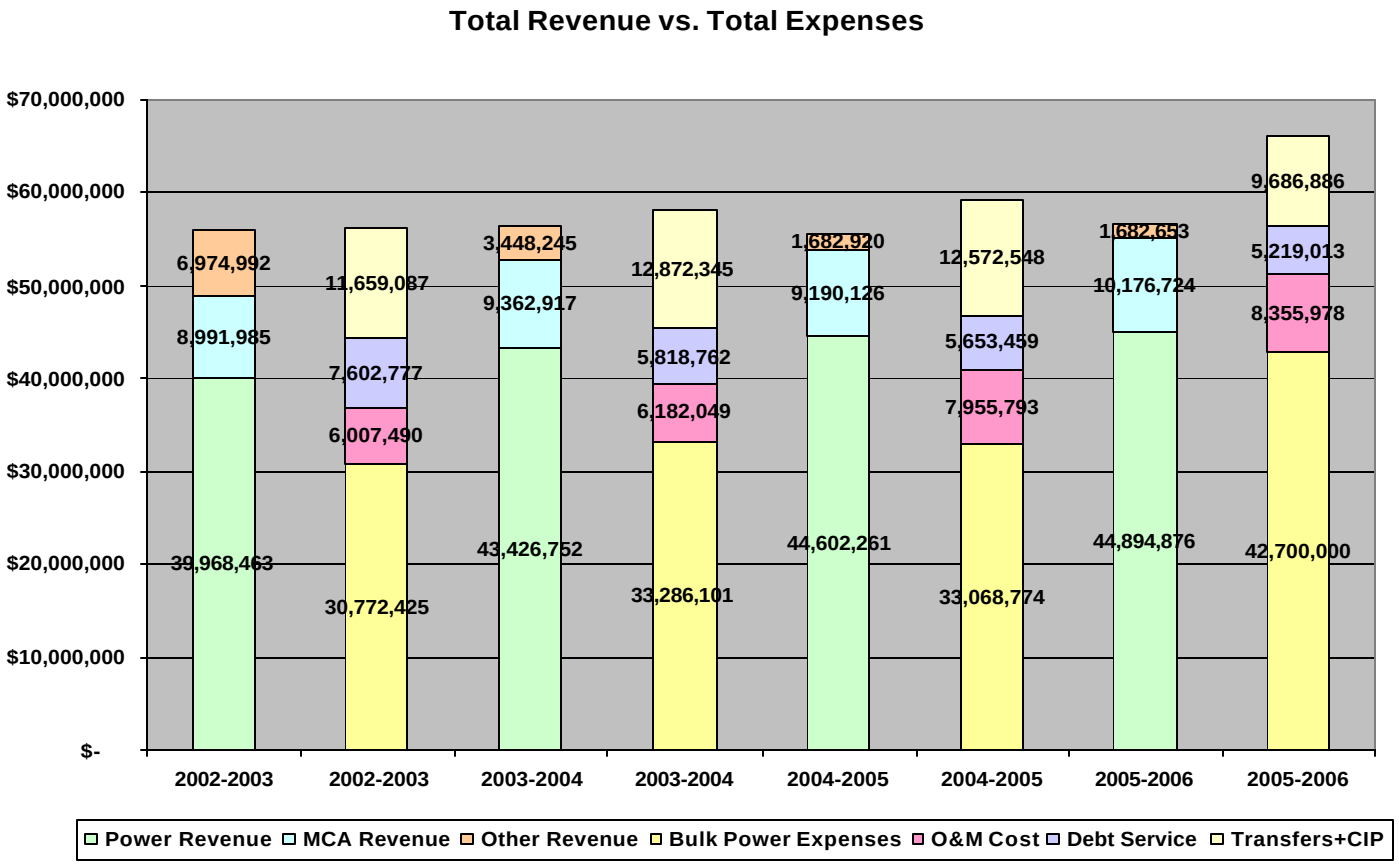
Financial Structure – Revenues



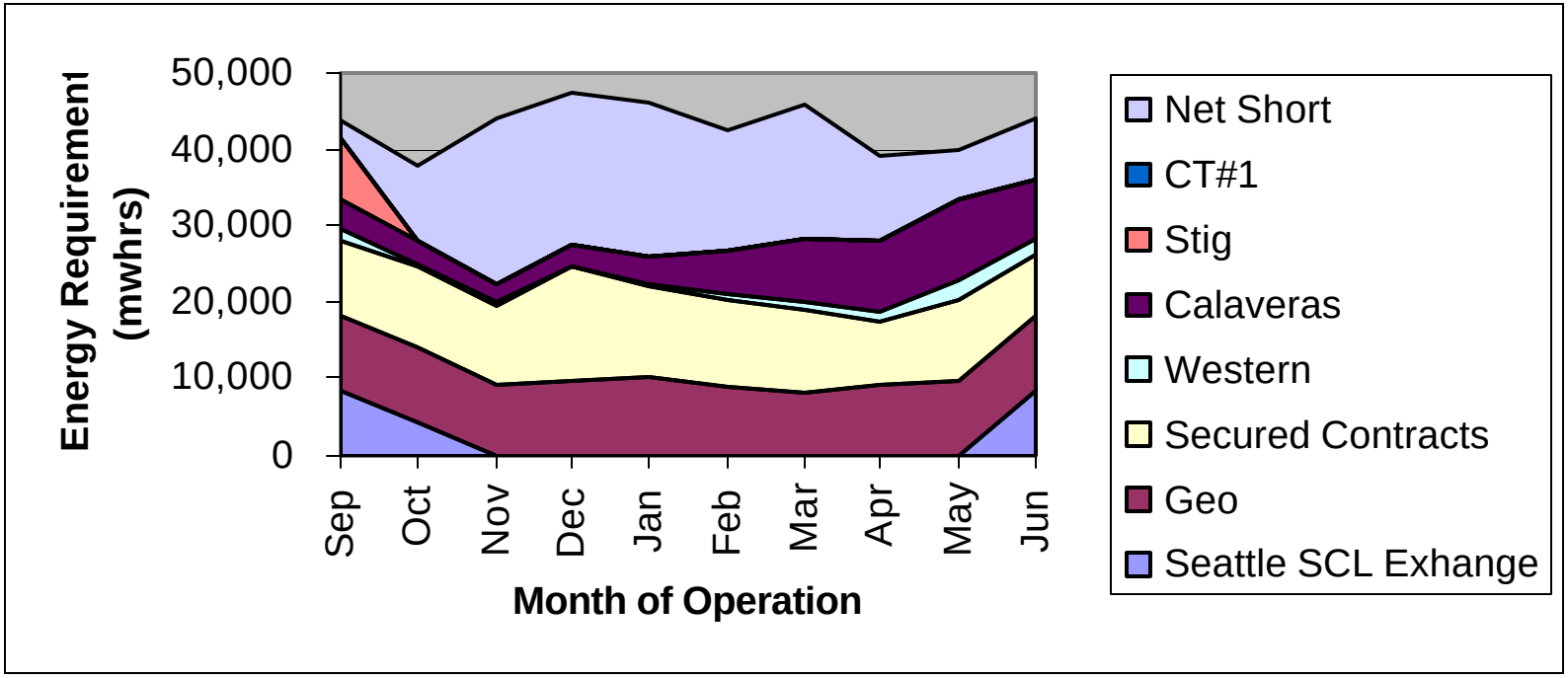
Power Sales	$ 55.1 Million
Investments	$ .95 Million
Services	$ .59 Million
Other	$ .14 Million
Total	$ 56.7 Million

Power Sales Investments Services Other

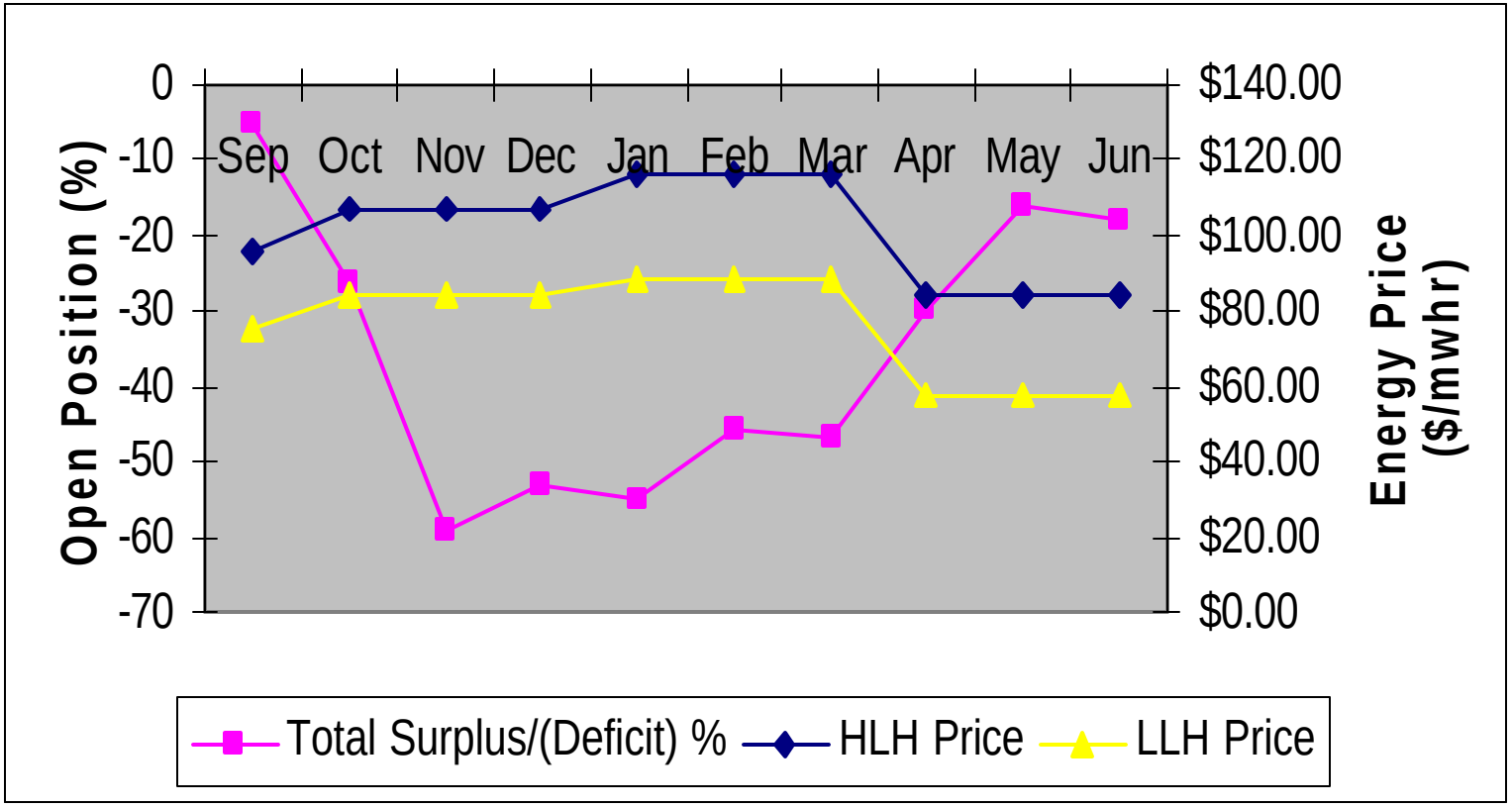
Financial Structure – Revenues and Expenses



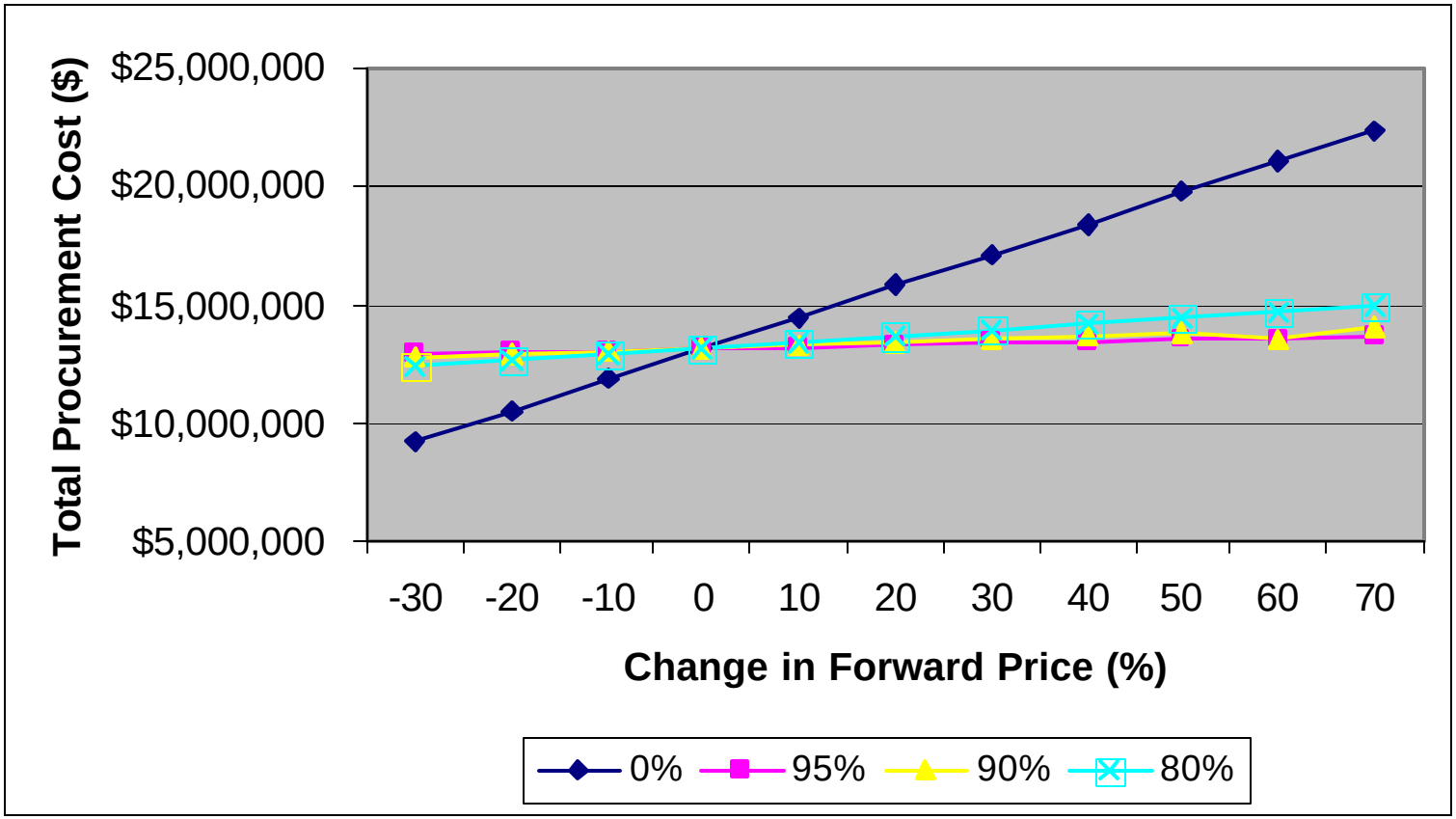
Energy Balance



Price vs. Short Position



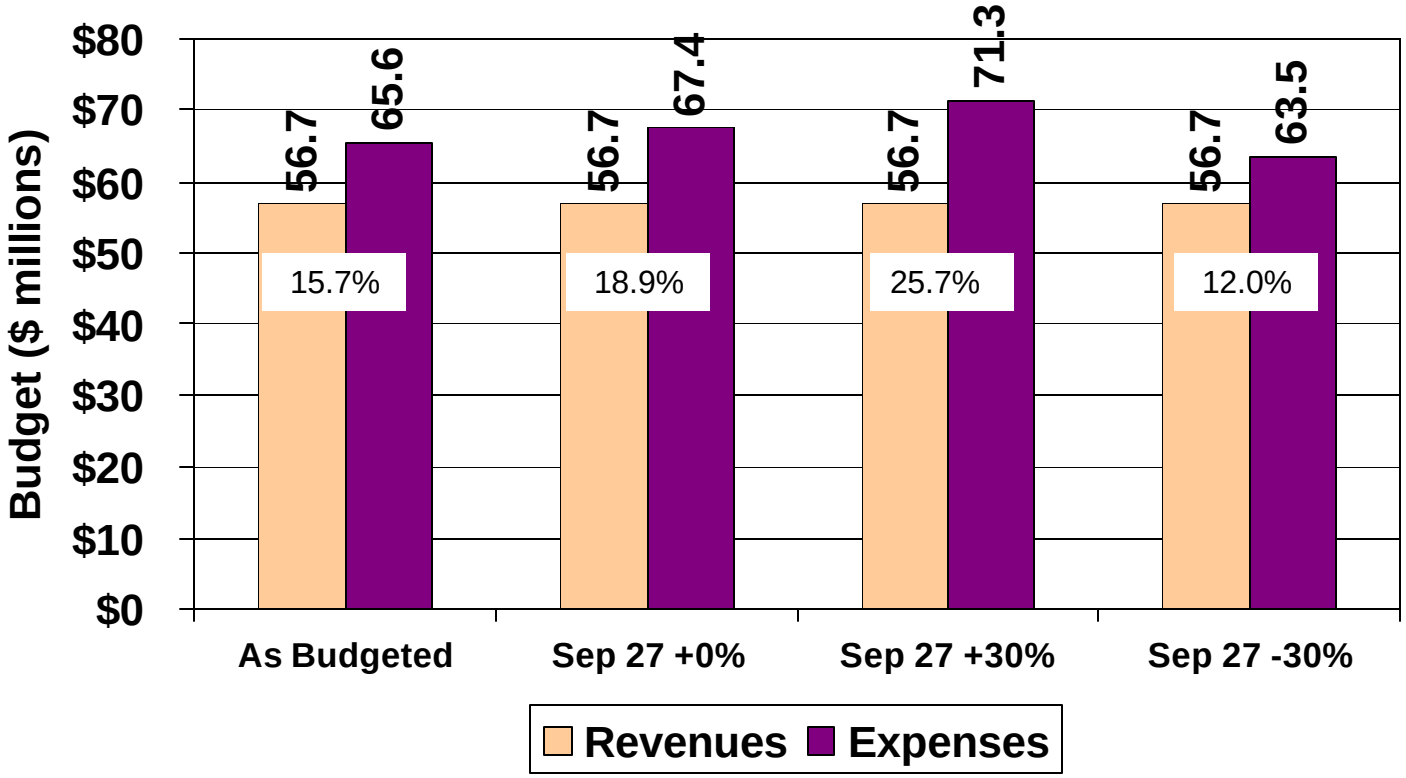
Open Position Sensitivity to Price Changes (9/27/2005)



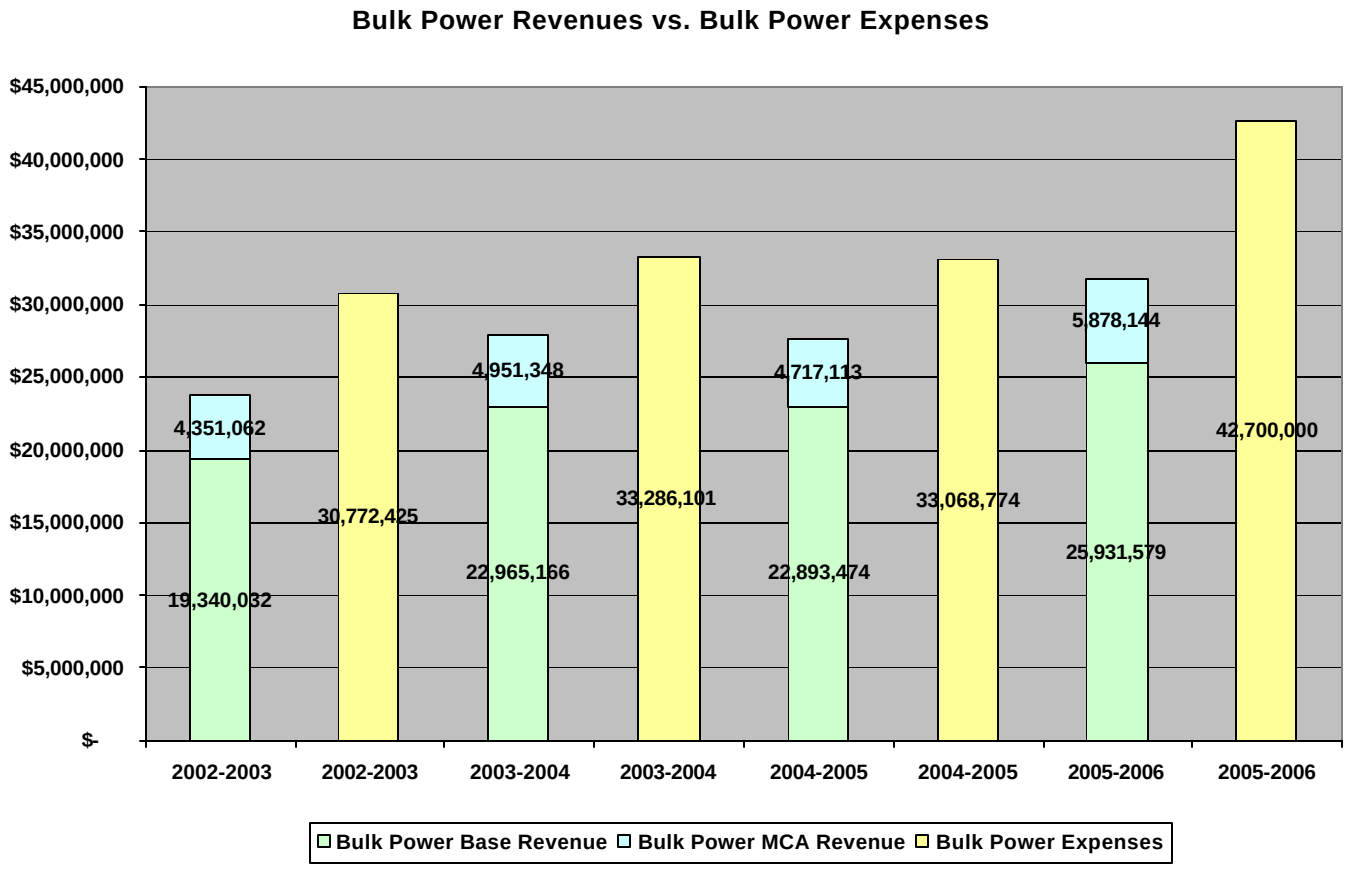
Issue – High Prices

- Hurricanes damaged gas supply infrastructure
  - Uncertainty in return to production
  - Diminished injection for future use
  - Projections of additional storms
- Competing requests for supply offers driving up prices
  - SCE
  - PG&E
  - APS

Budget Impacts of Changing Market Prices



Long Term - Revenues



Comparison of Forward Peak Prices vs Acutal Peak Prices